Responses to the Division of Consumer Advocacy's Information Requests

CA-HECO-IR-1

Ref: HECO Companies SOP at 4.

The HECO Companies state that there are a "very limited number of sites that are available to site new generation."

a. Provide copies of all siting studies performed by or for the HECO Companies.

b. To the extent not provided in the response to Part (a), for each of the HECO companies please:

   1. identify company-owned or controlled sites that could support new central or distributed generating facilities;

   2. provide an estimate of the maximum megawatt capability that each such site could support; and

   3. discuss all factors that might make it difficult for a non-utility generating facility to be located on each such site (i.e., taken individually).

HECO Response:

a. HECO objects to this information request on the grounds that (1) it is overly broad and unduly burdensome to provide a copy of "all siting studies performed by or for the HECO Companies" and (2) the term "siting studies" is vague and ambiguous and no definition of the term has been provided. An exhaustive search of HECO, HELCO and MECO records would need to be undertaken to find all such studies that could fit the meaning of a "siting study", including a search through archived files. HECO, HELCO and MECO have identified the following studies that may be applicable, dating back to 1974 for HECO, 1970 for MECO, and 1988 for HELCO. Copies of the reports are voluminous and can be reviewed at HECO's office by contacting George Hirose, HECO Regulatory Affairs, at 543-4787. The following reports are available for review:

HECO

- "Hawaiian Electric Company, Site Selection Study, Island of Oahu, Phase One", Stone & Webster Management Consultants, Inc., July 1974
- "Hawaiian Electric Company, Inc., Generating Facility Siting Study, Initial Candidate Sites Report", Black & Veatch, 1991
- "Hawaiian Electric Company, Inc., Generating Facility Siting Study, Candidate Sites Report:, Black & Veatch, January 1992
- "Hawaiian Electric Company, Inc., Generating Facility Siting Study, Preferred and Alternative Site/Technology Report", Black & Veatch, 1992

<u>MECO</u>

- "Site Location Study for a Steam Electric Generation Plant on the Island of Maui, Hawaii", Stearns-Roger Corporation, April 1970
- "Generation Expansion Study for Maui Electric Company", Gibbs & Hill Inc., December 1986
- Site Selection Study, Maui Electric Company, Ltd.", Stone & Webster Engineering Corporation, February 14, 1989
- "Maui Electric Company, Limited, Generating Facility Siting Study, Initial Candidate Sites Report", Black & Veatch, January 1991
- "Maui Electric Company, Limited, Generating Facility Siting Study, Candidate Sites Report, Black & Veatch, October 1991
- "Maui Electric Company, Limited, Generating Facility Siting Study, Preferred and Alternative Site/Technology Report", Black & Veatch, December 1991
- "Maui Electric Company, 1995 Unit Addition Project: Alternate Puunene Airport Site, Environmental Screening Report", Belt Collins & Associates, December 1992

- "Phase I Preliminary Site Assessment, Alternative Puunene Airport Site TMK 3-8-04:02 (Portion Of) Wailuku, Maui, Hawaii", Belt Collins Hawaii, July 1993
- Maui Electric Company, Ltd. "Central Maui Siting Study Air Quality Analysis", Trinity Consultants, Inc., April 1993
- "Environmental Assessment for Maalaea Generating Units 17, 18 & 19, Maui Electric Company, Limited," 1994
- "MECO Central Maui Siting Study", Belt Collins Hawaii, June 1994
- "Final, Environmental Screening and Siting Report for the Central Maui Generation Project", Dames & Moore, April 1995
- "MECO Generation Siting Study, Central Maui 232-MW Generation Station", Stone & Webster Engineering Corporation, November 1995
- "Maui Electric Company, Limited, Waena Generating Station, Wailuku and Makawao Districts-Island of Maui, Final Environmental Impact Statement", 1997
- "Distributed Generation Substation Site Selection Study for Maui Electric Company, Limited", prepared by Hawaiian Electric Company, Inc. and Maui Electric Company, Limited, May 2001[1]

<u>HELCO</u>

- "West Hawaii Site Study", CH2M Hill, August 1988
- "Summary Report of Candidate Power Plant Sites At Puu Anahulu North Kona, County of Hawaii, CH2M Hill, August 1990
- "Final Environmental Impact Statement, West Hawaii Landfill, Puuanahulu, North

Kona, Hawaii", R. M. Towill, 1991

- "Draft Environmental Impact Statement, West Hawaii Power Facility, Puu Anahulu, North Kona, Hawaii", CH2M Hill, May 1993
- "Final Environmental Impact Statement, Keahole Generating Station Expansion, North Kona, Hawaii, Hawaii Electric Light Company, Inc.", CH2M Hill, June 1993
- "Hawaii Electric Light Company, Inc., Temporary Transportable Dispersed Generation Site Selection Report", HECO, 1996
- "Hawaii Electric Light Company, Inc., Keahole Generating Station and Airport Substation Urban Reclassification, Final Environmental Impact Statement, North Kona, Hawaii," January 2005

b. Please see the responses to CA-IR-441 (filed with the Consumer Advocate by letter dated April 22, 2005) and CA-IR-442 (filed with the Consumer Advocate by letter dated April 21, 2005) in Docket No. 04-0113 for a discussion on locating distributed generation on HECO owned sites. (Please note that the response to CA-IR-41 includes confidential vendor and HECO information, which will be provided to the Consumer Advocate in Docket No. 04-0113 after an appropriate protective order is issued by the Commission.)

HECO's Barbers Point Tank Farm located in Campbell Industrial could accommodate approximately 200 to 300 MWs of new generation, depending upon the specific combustion turbine models installed in a combined cycle configuration. However, locating a non-utility generating facility at this site would be difficult because no excess space would be available after HECO installs its planned simple cycle unit addition in 2009.

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[1] The MECO Distributed Generation Site Selection Study contains information considered confidential due to concerns regarding security of MECO's transmission system. The study will be made available for review under an appropriate protective order.

No utility owned site has been identified on the island of Hawaii that could accommodate a new central generation station for HELCO.

MECO's Waena Generation Station site on Maui could accommodate approximately 232 MW of combined cycle generation.

In general, locating non-utility generators ("NUG") on utility sites would need to be assessed on a case-by-case basis to examine the factors that could make it difficult to do so. Specific physical and technical parameters of the NUG installation such as the technology to be installed, space and land area requirements, topographic slope and geotechnical constraints or recommended limitations, fuel logistics, water requirements, number of site personnel, access requirements, waste and emissions from operations, noise profile, electrical interconnection requirements, physical profile, etc., would need to be provided by the NUG in order for the utility to evaluate the feasibility of the installation. Other factors that would need to be assessed include how the operation, maintenance and construction of each installation would affect:

- maintaining security of the site;
- land ownership;
- land use and permit considerations (compatibility of the proposed development on present and planned land uses);
- existing and new environmental permits and licenses;
- impact on operations and maintenance of existing and future facilities; and
- impact to the surrounding community
- change in zoning permit conditions
- safety of utility personnel.

CA-HECO-IR-2

Ref: HECO Companies SOP at 4.

a. Please provide the basis for the claim that "extended time ... must be allocated to conduct the necessary environmental review for, and to permit and obtain the necessary approvals for, new generation."

b. Provide copies of all studies of the time required for environmental review and permitting that have been performed by, or for the HECO Companies.

c. Provide copies of all other documents that support this claim.

HECO Response:

a. Installation of new central station generating capacity will trigger a variety of different types of permits and approvals depending on the location of the proposed site, technology being considered, and other considerations. An example of the extended time that needs to be allocated for permitting approvals is the Covered Source/Prevention of Significant Deterioration (CS/PSD) permit which is administered by the State of Hawaii Department of Health ("DOH") and the United States Environmental Protection Agency ("EPA"). The most recently issued CS/PSD permit for installation of a new large generating unit was issued to Maui Electric Company for its Maalaea M18 unit. The application to the DOH was submitted in December 1998 and the permit was received in July 2004. CS/PSD permitting review time periods for other MECO and HELCO units are as follows:

Unit	Date of Application	Effective Date of Permit	No. of Months
Keahole CT-4/CT-5	01/93	11/01	106
Maalaea 17-19	08/94	09/98	49
Miki 7-8	11/93	05/96	30
Palaau 7-9	05/93	12/95	31

Maalaea 16	09/90	09/92	24
Puna CT-3	08/90	03/92	19
Maalaea 14-15	04/90	01/92	21
Keahole CT-2	05/88	08/89	15
Maalaea 12-13	02/87	12/89	34
Maalaea X1-X2	05/86	11/87	18
Keahole 20-23	10/85	11/87	25

(Please note that the Keahole CT-4/CT-5 CS/PSD application and approval time included two appeals to the EPA's Environmental Appeals Board.)

The CS/PSD permitting review process is quite rigorous and requires extensive participation by both the applicant and the regulating authority to be completed. Time periods can also be heavily influenced by the extent of public participation involved and the time required to respond to public comments and questions.

The time required for acceptance of an Environmental Impact Statement ("EIS") can vary, depending on the circumstances of the project. For example, for MECO's Waena Generating Station EIS, the EIS preparation notice was published on March 8, 1997, and the Final EIS was accepted by the County of Maui in November 1997 (approximately eight months). For HELCO's Keahole Generation Expansion EIS, the EIS preparation notice was published on September 8, 1992, and the Final EIS was accepted by the State Department of Land and Natural Resources in January 1994 (approximately 16 months).

In addition, although not a generation project, the EIS process for the proposed Kamoku-to-Pukele Transmission Line Project took 21 months from inception to acceptance. Finally, until 2004, not all generation projects required environmental review.

In 2004, however, HRS Chapter 343 was amended to require environmental review for new or expanded power generating facilities where the new fossil fuel-fired equipment's output exceeds 5 megawatts. Thus, all but the smallest fossil fuel-fired generation projects are now subject to environmental review.

b. No specific studies have been prepared other than a general review of historic time periods for CS/PSD review and EIS approval for HECO, MECO, and HELCO projects, as indicated in the response to part a. above.

c. The supporting documents (i.e., HECO, HELCO or MECO CS/PSD permit applications and DOH approvals) are voluminous and can be reviewed at HECO's office by contacting George Hirose, HECO Regulatory Affairs, at 543-4787.

CA-HECO-IR-3

<u>Ref: HECO Companies SOP at 4.</u>

HECO states that there are "limited fuel options that are economically available in Hawaii."

a. Please provide copies of all studies of fuel options that have been performed by, or for the HECO Companies.

b. Provide copies of all other documents that address the economics of utilizing fossil and renewable fuels in Hawaii.

<u>HECO Response:</u>

a. The following fuel reports were prepared for HECO. The reports are voluminous, and can be reviewed at HECO's office by contacting George Hirose, HECO Regulatory Affairs, at 543-4787.

   - "Coal Feasibility Study for Hawaiian Electric Company", Stearns-Roger, 1978;
   - "Hawaiian Electric Company, Inc., Alternative Fuels Study, Final Report", Fluor Engineers, Inc., December 1984; and
   - "Hawaiian Electric Company, Inc., Alternative Fuels Study, Phase II, Final Report", Fluor Technology, Inc., September 1987.

b. HECO objects to this information request on that grounds that (1) it is overly broad and unduly burdensome to produce a copy of "all other documents that address the economics of utilizing fossil and renewable fuels in Hawaii", and (2) the term "document" is vague and ambiguous and no definition of this term has been provided. In addition, HECO is unaware of <u>all</u> the documents produced outside the Companies that address the economics of utilizing fossil and renewable fuels in Hawaii. Without waiving its objections, HECO has identified the following non-Company documents, which are voluminous, that are available for review at HECO's office by contacting George Hirose, HECO Regulatory Affairs, at 543-4787:

- Hawaii Energy Strategy Project 2: Fossil Energy Review, "Task I, World and Regional Fossil Energy Dynamics", prepared for the State Department of Business, Economic Development & Tourism, Energy Division, by The East-West Center Program on Resources: Energy and Minerals, December 1993,
- Hawaii Energy Strategy Project 2: Fossil Energy Review, "Task II, Fossil Energy in Hawaii", prepared for the State Department of Business, Economic Development & Tourism, Energy Division, by The East-West Center Program on Resources: Energy and Minerals, December 1993,
- Hawaii Energy Strategy Project 2: Fossil Energy Review, "Task III, Greenfield Options: Prospects for LNG Use", prepared for the State Department of Business, Economic Development & Tourism, Energy Division, by The East-West Center Program on Resources: Energy and Minerals, December 1993,
- Hawaii Energy Strategy Project 2: Fossil Energy Review, "Task IV, Scenario Development and Analysis", prepared for the State Department of Business, Economic Development & Tourism, Energy Division, by The East-West Center Program on Resources: Energy and Minerals, December 1993, and
- "Assessment of Coal Technology Options and Implications for the State of Hawaii", Decision and Information Sciences Division, Argonne National Laboratory, sponsored by State Department of Business, Economic Development & Tourism, December 1993.
- "Hawaii Hydrocarbon Outlook", FACTS Inc., January 2003 (Report is available at: http://www.hawaiienergypolicy.hawaii.edu/pages/reports.html)
- Evaluating Liquefied Natural Gas (LNG) Options for the State of Hawaii, FACTS,

Inc, January 2004 (Report is available at:

http://www.hawaiienergypolicy.hawaii.edu/pages/reports.html)

CA-HECO-IR-4

Ref: HECO Companies SOP at 4.

The HECO Companies state that there may be "practical limits on the amount of purchased power that a utility can practically integrate into an island system."

a. Please identify all such "practical limits" for:

   1. HECO;

   2. HELCO; and

   3. MECO.

b. Provide copies of all documents that support the identified limits for each of the HECO companies.

HECO Response:

a. The full paragraph from page 4 of HECO's SOP is provided below:

> "In order to accommodate the addition of as-available renewable energy resources into a small, isolated island system, Hawaii utilities must carefully assess the types and mix of other resources added to its system. For example, other generating resources should be dispatchable down to minimum operating levels, and be able to cycle on and off on a daily basis so that they are off at the time of the system minimum peaks during the middle of the night. Moreover, there may be practical limits on the amount of purchased power that a utility can practically integrate into an island system. These factors would have to be considered in any competitive bidding process."

The intent of the paragraph is to communicate to the parties that small, isolated island systems have unique issues which should be considered if a competitive bidding process is developed in Hawaii. One of these issues is the amount of purchased power that can be integrated. At this time, HECO, HELCO, and MECO have not identified specific "practical limits" for their systems. For the time being, HECO, HELCO, and MECO are attempting to use power purchase contract provisions and performance standards as a mechanism to facilitate the integration of purchased power into the utility's grids while maintaining grid integrity and operational flexibility. This particular strategy addresses each power producer on a project-specific basis, but does not preclude the need for system-wide "practical limits" in the future.

b. The power purchase agreements ("PPA") between HECO, HELCO or MECO and Independent Power Producers ("IPPs") contain provisions that govern over coordination of IPP maintenance outages with the utility's maintenance schedules, dispatch of the IPP units, and performance standards. (The Consumer Advocate received a copy of the PPA in the application requesting approval of the PPA.) These provisions are developed on a project-specific basis based on the conditions that exist on the utility's grid at the time the PPAs are negotiated. For example, specific performance standards that are set within a particular PPA will be a function of the other units on the grid, the characteristics of those units (in terms of their rotational inertia, ramp rates, droop response, and other parameters), the overall "stiffness" of the grid as quantified by the "frequency bias", and other factors.

CA-HECO-IR-5

Ref: HECO Companies SOP, Appendix 1, at 9.

Please provide an estimate of the "cost to the host utility" for the development and implementation of HECO's 1987 RFP (i.e., on a "present worth" and "per kWh acquired" basis).

a. Please provide an estimate of the value of the purchased power contracts that resulted from HECO's 1987 RFP (i.e., on a "present worth" and "per kWh" basis).

b. Please provide an estimate of the costs to HEI for the development and implementation of each of its recent RFPs (i.e., on a "present worth" and "per kWh" basis).

c. Provide copies of all documents that support each of the above costs estimates.

HECO Response:

HECO does not believe it would be meaningful to compare HECO's 1987 RFP with the RFP process under consideration in this proceeding. As explained on page 32 of Exhibit A, competitive bidding processes are evolving with changes in the power market. Therefore, it could be misleading to use costs from 18 years ago as a "benchmark" for future RFPs. For example, the impacts of direct and imputed debt as a component of the bid evaluation process are being recognized by a number of regulatory commissions and utilities as an important factor in evaluating and selecting resource options (pg 33 of Exhibit A). As explained on page 1 of Exhibit C, FASB issued FIN46 in January 2003, so from an accounting perspective, the analysis of purchased power agreements using today's accounting rules are more complex than the 1987 timeframe. Another example is that more RFP processes include all costs in the analysis, including transmission costs and system costs. The ability to install transmission infrastructure in a timely manner has become more difficult since 1987, and the analysis used to consider this in the RFP process will likely become more complex as a result.

In any event, HECO does not know the "cost to the host utility" for the development and implementation of HECO's 1987 RFP (i.e., on a "present worth" and "per kWh acaquired" basis). Information regarding engineering costs related to the development and implementation of the RFP, which took place almost 20 years ago, is no longer available.

a. HECO assumes that the CA meant to refer to Appendix A at page 9. Response to HECO's 1987 RFP resulted in negotiations which ultimately resulted in two purchase power contracts: AES-Barbers Point, Inc. (now known as AES Hawaii, Inc.) and Kalaeloa Partners, L.P.. (See also the response to CA-IR-12, part a.) An evaluation of the AES contract at the time Commission approval of the contract was requested estimated net present value of the contract of $5,564 million and 10.48¢ per kwh purchased (HECO-706 in Docket No. 6177). An evaluation of the Kalaeloa contract at the time Commission approval of the contract was requested estimated net present value of $7,089 million and 12.02¢ per kwh purchased (HECO-706 in Docket No. 6378).

b. Renewable Hawaii, Inc. ("RHI"), a non-regulated subsidiary of HECO, is seeking opportunities for equity investment in commercially viable and cost effective renewable energy projects to produce electricity for Hawaii. RHI aims to partner with renewable energy developers, taking a minority interest and thus contributing financing to these renewable energy projects. RHI has released a round 1, phased renewable energy request for project proposals ("RE RFPP") in 2003 and 2004 for Oahu, then Maui, Molokai and Lanai, and finally Hawaii. RHI has recently released a second round of the RE RFPP in March 2005. The ultimate outcome of these RE RFPPs is to sign investment agreements with the renewable energy developer. The renewable energy developer will have to obtain all permits and approvals, including a Public Utilities Commission approved power purchase agreement with the local utility. RHI received 17 proposals in round 1, of which 6 projects passed the screening. RHI is working with these 6 project developers in signing memorandum of understandings, investment agreements and continued due diligence on the projects.

The objective for RHI's RFP is different from the objective for a competitive bidding objective for new generation RFP. The decision for RHI to make a passive investment in a project is based on project team and management, commercial technology and financial output evaluation. The decision for a utility to accept new generation will be based on a number of factors such as reliability, characteristics of generating unit, control of this unit, state energy policy, firm versus as-available, costs, transmissions needs, time, new accounting practices and other factors. Thus, time and resource needs will vary for each objective. RHI has tracked the resource requirements for the RE RFPP development, release and evaluation. However, since the process is on-going and not completed yet, the information would not be complete. It is also unclear as to what is meant by the request for "cost per kWh" basis.

c. See the response to part b.

CA-HECO-IR-6

Ref: HECO Companies SOP at 12.

The SOP states "The HECO Companies prefer that the procedures be developed and adopted in a framework proceeding, like that used to develop the IRP Framework, rather than a rulemaking proceeding."

a. What is meant by "a framework proceeding?"

b. Would the result be enforceable rules or something different? Please explain.

HECO Response:

a. A "framework proceeding, like that used to develop the IRP Framework", as referred to on page 12 of the Companies SOP, refers to a proceeding like Docket No. 6617, in which the Commission adopted "A Framework for Integrated Resource Planning" (revised May 22, 1992). The framework, as revised May 22, 1992, was attached to Decision and Order No. 11630, issued May 22, 1992 in Docket No. 6617 ("Instituting a Proceeding to Require Electric Utilities to Implement Integrated Resource Planning").

b. The contemplated result of a "framework proceeding" is a set of guidelines, in the form of an enforceable Commission order, established by the Commission for a particular utility process (e.g., in the case of Docket No. 6617, enforceable guidelines for the conduct of integrated resource planning by the electric and gas utilities subject to the Commission's jurisdiction). The result is similar to rules, but the procedures used to adopt the framework included an evidentiary hearing conducted pursuant to H.R.S. § 91-9 to test the recommendations of the various parties to the proceeding, and an evidentiary record upon which the Commission can base a decision, as opposed to a rulemaking proceeding conducted pursuant to H.R.S. § 91-3, which involves a public hearing and comment process. (The Commission can conduct a public hearing in connection with a framework proceeding if it so chooses, and can incorporate elements such as workshops and a panel format hearing if it so elects.) In the Companies' view, a framework is easier to administer and modify, due to the technical requirements applicable when rules are amended. A framework can allow for flexibility in the way it is applied, and can more easily account for differences in the utilities subject to the framework. (A framework proceeding might be too cumbersome if there were numerous electric utilities, but there are only four in Hawaii.)

CA-HECO-IR-7

a. Do the HECO Companies have a view of what is lacking (i.e., by way or rules or changes needed to implement competitive bidding) in the Commission's current regulatory framework?

b. If so, please state what specific rule changes or other changes the HECO Companies would propose to implement?

c. Please state whether and how each of the changes identified in response to Part (b) would have improved for customers the results of HECO's 1987 RFP for power supplies.

HECO Response:

a. The Companies' position is that they can support competitive bidding for certain forms of new generation, but only if it is structured in such a fashion that the potential benefits can be realized, and the potential disadvantages can be mitigated or eliminated, and that appropriate exceptions are recognized. SOP, page 2. At the same time the Companies have reservations about the effectiveness of competitive bidding in an island system such as Hawaii. If competitive bidding is implemented, there are a number of potential shortcomings or pitfalls that need to be addressed to ensure that a competitive bidding system provides benefits to customers and shareholders. The Companies can appreciate some of the potential benefits of competitive bidding but support the implementation of competitive bidding only if the process is designed in such a way that the benefits occur instead of the pitfalls. SOP, Exhibit A, pages 15, 28.

Before the Companies are able to identify "what is lacking" in the "Commission's current regulatory framework", and state "what specific rule changes or other changes the HECO Companies would propose to implement", the Companies will need to have a more concrete understanding of the guidelines for the competitive bidding process to be used. In other words, a number of questions concerning the competitive bidding process to be used must be answered in order for the Companies to respond to this information request. For example, the Companies will need to know what is the role of competitive bidding. Will the competitive bidding process be one that is (a) required, (b) required, subject to exceptions, (c) encouraged but not required, or (d) something else? In addition, the Companies will need to know what is the role of the Commission. Will the Commission's include (a) approving the RFP, (b) approving the evaluation criteria, or (c) just approving the projects or agreements resulting from the process?

Also, the Companies will need to know whether there are any constraints or requirements going to be imposed on the utility conducting a competitive bidding process. As is indicated in the Companies' SOP, given their size and circumstances, the utilities need to be able to include their build/own projects in the process, put together the RFP, review and evaluate the bids, select the winning bid(s), and negotiate the terms and conditions of a PPA (if an IPP project is selected) or a purchase arrangement (if a build and transfer project is selected). The Companies are proposing a broad role for the utilities, if and to the extent competitive bidding is adopted, in which case the adopted framework would confirm that role.

Further, the Companies will need to know what is the role, if any of an independent observer. Will an independent observer be required or encouraged? If so, will the independent observer manage the correspondence between the utility and bidders, review and audit the results of the evaluation process, and advise the utility if there are any fairness issues, as the Companies have suggested might be the role of an independent observer?

The Companies will also need to know whether the timing of any regulatory review and approval steps included in the process will be expedited. Will the timing of the review and approval process be expedited so as to provide sufficient time to install generation before it is needed? It would be imprudent to apply a new competitive bidding process to new generation that must be added sooner than generation could be added using the process that has yet to be developed. The review and approval process will need timely milestones so that the process will work.

Moreover, the Companies will need to know what the effect of competitive bidding will be on avoided costs and the Commission's rules regarding qualifying facilities and non-fossil fuel producers. Will the results of a competitive bidding process be used to determine avoided costs? Will a utility still have an obligation to negotiate with an independent power producer outside of the competitive bidding process?

In addition, the Companies will need to know which of the possible ways to integrate competitive bidding into IRP, if any, will be used. Possible scenarios were discussed by the Companies and the CA in their statements of position.

Furthermore, the Companies will need to know how the issue of the impact of purchased power costs on the utilities' balance sheets and the potential for utility credit downgrades (and higher borrowing costs) as a result will be handled. If the utilities will have to restructure their balance sheets and increase their percentage of more costly equity financing in order to offset the impacts of purchasing power on their balance sheets, then this rebalancing cost must also be taken into account in evaluating the total cost of the new generating unit. Utilities are just starting to gain experience with the impact of FIN 46R on purchased power arrangements.

Accordingly, until answers to these types of questions are known, the Companies cannot propose specific framework provisions (which is the Companies' preferred approach or rule changes if a framework approach is not adopted). In general, however, the Companies note that a good framework should be flexible enough to permit tailoring the process to the specific circumstances, yet specific enough to avoid after-the-fact determinations of fundamental process matters (e.g., whether the utility should have used separate utility project proposal and bid evaluation teams - - which generally would be impractical in Hawaii). This will provide flexibility, while helping to avoid attempts by losing bidders to undo a completed competitive bidding process (which would delay the addition of needed resources), no matter how fairly the bidding and evaluation process actually was conducted.

b. See the response to subpart a above.

c. Please see the response to subparts a and b, above. The Companies' understanding is that the reference to "HECO's 1987 RFP for power supplies" refers to HECO's Purchase Power Alternatives Request for Proposal that was issued on June 4, 1987 that was originally sent to thirty-one interested parties. Comparisons to the 1987 RFP are not useful. As is discussed in more detail in the attachment to the response to CA-HECO-IR-12, HECO's 1987 RFP was a limited purpose RFP. The RFP primarily called for responders to consider a 146 MW steam unit in accordance with the design specifications for a HECO proposed unit (i.e., Kahe 7). The RFP did not limit responders to the Kahe site or to HECO's chosen technology. (The RFP resulted in HECO entering into two purchase power agreements ["PPA"] and the construction of two QF projects at oil refinery sites located at Campbell Industrial Park.) The RFP did not have a form of PPA attached to it. Both PPAs were the subject of lengthy negotiations.

CA-HECO-IR-8

Ref: HECO Companies SOP at 11.

Please identify the key elements of the process that "has yet to be developed."

HECO Response:

Whether a bidding process is developed or not, there are still a large number of important elements/tasks that have to be developed/completed before a competitive bidding process can be effectively initiated. These are the tasks and processes typical of effective competitive bidding programs as undertaken by most utilities. For an initial list and description of several of the key elements of the process that need to be developed/completed to effectively undertake competitive bidding, please refer to the response to Issue 2b of Exhibit A, pages 34 through 40 of HECO's Statement of Position.

CA-HECO-IR-9

<u>Ref: HECO Companies SOP at 6-7; Competitive Bidding Objectives.</u>

Is it the HECO Companies' position that "a specific competitive bidding process" should be established (a) before, or (b) after, definition of a "product that meets the buyer's needs?" Please explain.

<u>HECO Response:</u>

The Companies' SOP (page 6) states ""[t]he objectives of competitive bidding should be established to assess whether competitive bidding in general, or a specific competitive bidding process, will be beneficial." The Companies' SOP (page 7) adds that "[t]o establish objectives, the purpose of a competitive bidding process should first be identified. Generally, a product buyer will implement a competitive bidding process in order to acquire a product that meets the buyer's needs (i.e., in terms of quality, quantity, and time and assurance of delivery) at the lowest cost. The key points are that the process is only implemented if it benefits the <u>buyer</u> using the process, and the products acquired using the process will meet the <u>buyer's</u> needs."

The decision as to whether to implement competitive bidding, as well as to what competitive bidding process should be implemented, should be made in light of the product to be acquired. In this proceeding, the product to be acquired is new generation for one of Hawaii's four electric utilities, one of which is a small electric utility cooperative. Thus, Hawaii specific factors should be considered.

As stated in the Companies' SOP (page 7), "[i]n order to meet the needs of a small, isolated utility, the generation acquired under a competitive bidding process must meet the needs of the utility in terms of the reliability of the generating unit, the characteristics of generation needed by the utility, and the control that the utility needs to exercise over the operation of the generating unit in order to integrate the unit into its system."

Hawaii specific factors that must be taken into consideration include factors such as (1) the very limited number of sites that are available to site new generation, and the difficult, time-consuming and uncertain process that must be followed to change land use designations in Hawaii in order to acquire new sites for generation, (2) the extended time that must be allotted to conduct the necessary environmental review for, and to permit and obtain the necessary approvals for, new generation, (3) the utility and island-specific constraints that constrain the size of new generation that can be added to the systems, and (4) the limited fuel options that are economically available in Hawaii.

A "conceptually sound" process that works on the mainland, but ignores Hawaii's unique characteristics, could result in substantial harm to Hawaii's electric infrastructure, to the ability of Hawaii's electric utilities to meet the growing electricity needs of their customers, and to Hawaii's economy. The process must provide for exceptions if implementing the process could negatively impact the ability of Hawaii's electric utilities to add generation in a timely fashion.

Any process established by a Commission adopted framework must also be flexible enough to take into account further delineation of the specific product (i.e., the generation needs of the electric utility using the process) at the time an RFP is issued.

For example, the specific competitive bidding process used may differ depending on the type of generation to be acquired. For instance, the competitive procurement process for distributed generation ("DG") may be different than the competitive procurement process for generation that provides power directly to the utility or sells power to the utility. The competitive procurement procedure that the Companies propose to use for combined heat and power ("CHP") systems that are installed at customer sites was detailed in the generic DG investigation, Docket No. 03-0371.

Also, as-available renewable energy generation has different characteristics than firm capacity, and the timing of when such resources are added to the utility's system is not nearly as important to the reliability of the system. It may be appropriate to establish a separate competitive procurement process to acquire as-available renewable energy generation, particularly given the state energy policy that favors the development of renewable energy generation.

CA-HECO-IR-10

Ref: HECO Companies SOP, Exhibit A at 2.

a. Have the HECO Companies performed, or otherwise acquired, any assessment of the markets that might be tapped through competitive bidding processes?

b. If the response to Part (a) is answered in the affirmative, please provide copies of all related documents.

HECO Response:

a. HECO has not performed a detailed assessment of the market entities that may bid into a competitive bidding process. HECO is familiar with the entities that do business in Hawaii as well as the commercially viable technologies but is not certain who may elect to bid in such a process. Given limitations associated with the potential size of the solicitation, sites, permitting schedule, etc. it is not certain if traditional mainland power generators will decide to bid.

b. Not applicable.

CA-HECO-IR-11

Ref: HECO Companies SOP, Exhibit A at 15.

a. Which of the "several approaches for instituting competitive bidding" do the HECO Companies favor? Please explain.

b. Does HECO currently have a need (i.e., as that term is used on page 16) that would justify implementation of this approach? Please explain.

HECO Response:

a. Page 15 of Exhibit A contains an important prelude to the discussion of competitive bidding approaches used on the mainland:

> "HECO has reservations about the effectiveness of competitive bidding in an island system such as Hawaii. If competitive bidding is implemented, there are a number of potential shortcomings or pitfalls that need to be addressed to ensure that a competitive bidding system provides benefits to customers and shareholders. HECO can appreciate some of the potential benefits of competitive bidding but supports the implementation of competitive bidding only if the process is designed in such a way that the benefits occur instead of the pitfalls."

The Exhibit then describes three approaches for instituting competitive bidding on the mainland: 1) adoption of rules and guidelines first, through a formal regulatory process, prior to initiation of the actual competitive solicitation, 2) development of the bidding procedures and RFP via a collaborative process, with input from a number of parties, and 3) independent development and issuance of the RFP by the soliciting utility, generally without input from outside entities. These are described at a conceptual level, and at this time, HECO is not characterizing any of these options as having benefits which exceed pitfalls. HECO's favored approach is one that takes the time necessary to address the Potential Shortcomings described on pages 15 through 17 of Exhibit A. As stated on Page 17:

> "HECO's position is that the process to develop an effective and fair competitive bidding process will be time consuming. However, it is important that sufficient time be allocated to ensure the process is adequately developed and potential pitfalls and shortcomings can be discussed and resolved."

b. HECO currently has a "need" for new generation; however, it would be difficult to justify any process that does not satisfy this need. As stated on page 11 of the HECO SOP:

> "It would be imprudent to apply a new competitive bidding process to new generation that must be added sooner than generation could be added using the process that has yet to be developed."

CA-HECO-IR-12

Ref: HECO Companies SOP, Exhibit A at 8.

HECO states that "a three to four year time horizon from the development of the competitive bidding procedures to development and issuance of the RFP … is not unusual."

a. Please state whether HECO has records of the process and implementation documentation from its 1987 RFP, or access to RFP process and implementation documentation through its consultants.

b. Please identify each RFP that HECO (or its consultants) is aware of that resulted in a signed PPA, where the approach used was consistent with that described under item (3) on page 16 of Exhibit A.

c. Please identify each RFP that HECO (or its consultants) is aware of that resulted in a signed PPA and in which the time to develop (perhaps using already-available documentation) and implement the RFP was less than three to four years.

d. For each RFP described in Part (c), please identify the duration of the RFP, stating in each instance the event that signified the beginning and end of the process.

HECO Response:

Please note that HECO's reference to a three to four year time horizon includes the development of the competitive bidding guidelines or procedures, development and issuance of the RFP, and completion and approval of contracts. This schedule is based on the development and implementation of competitive bidding processes for long-term resource options (i.e., 20-30 year contracts).

a. HECO does not have all of the requested information regarding its 1987 RFP. Information regarding the 1987 RFP was provided in Docket No. 6177. A summary of the events that led to the 1987 RFP is attached as pages 4-7. HECO is uncertain of the time it took to develop the RFP. The RFP for purchased power alternatives was issued in June 1987, with responses received in August 1987. A power purchase agreement was signed with AES-Barbers Point, Inc. (now known as AES Hawaii, Inc.) in March 1988, and with

Kalaeloa Partners, L.P. in October 1988.

b. HECO and its consultants are aware of a few specific examples of RFPs that have been undertaken where the approach was generally consistent with the approach described under item (3) on page 16 of Exhibit A of HECO's SOP. BC Hydro recently conducted a Call for Tenders process consistent with the approach described under item (3). In addition, Duke Power has solicited bids for power supplies based on its own RFP process, without the presence of formal bidding rules or procedures in the states in which the utility serves.

c. HECO and its consultants can cite several examples of recent RFPs and Call for Tenders in which the time to develop and implement the RFP was less than three to four years. In several cases, the bidding rules and/or guidelines had previously been established prior to development and implementation of the RFP. Examples include: (1) Hydro-Quebec Distribution Call for Tenders for 1,200 MW of Firm Capacity and Associated Energy (A/O 2002-01); Firm Capacity for 100 MW of Electricity Generated Using Biomass (A/O 2003-01); and 1,000 MW of Wind-Generated Electricity (A/O 2003-02); (2) Portland General Electric 2003 Request For Proposals; (3) Pacificorp RFP for Electric Resources (RFP 2003-A); and (4) BC Hydro Call for Tenders.

d. Attached page 8 provides the schedule for each of the RFPs listed above. While some of the dates may be vague and not exact, the schedule represents the recollection of HECO's consultants regarding the timeframe of the RFP process. In addition, the timeframe for developing the rules and procedures which underlie the RFP process are discussed where warranted.

The timeframe for developing and implementing an RFP process depends on a number of factors including the following: (1) Whether or not competitive bidding rules or procedures were already in place before issuance of the RFP; (2) whether or not the host utility has had recent experience with development and implementation of an RFP process; and (3) the type of resources solicited. For example, in Hydro-Quebec's case, the Company has issued several Calls for Tenders. The initial Call for Tenders for 1,200 MW of firm capacity and associated energy took longer to develop and implement than subsequent processes.

For the Portland General Electric RFP, the bidding rules and guidelines were already in place before the RFP process began. The process of developing the competitive bidding guidelines in Oregon began in May 1989, when the Oregon Public Utility Commission ordered an informal staff investigation into the potential use of competitive bidding as a means for investor-owned electric utilities to acquire energy resources. The Competitive Bidding Guidelines were adopted in October 1991 in Order 91-1383, over two years later. Thus, while it took less than the three to four years to develop and implement the most recent Portland General Electric RFP process, the existence of the competitive bidding guidelines served to reduce the schedule for development and implementation of the RFP. If the timeframes required for the development of the bidding rules and conduct of the RFP process are considered, the total time approaches the four year schedule identified.

While attached page 4 provides the schedule for undertaking the competitive bidding process only, HECO's statement about the time required to undertake a competitive bidding process includes development of competitive bidding guidelines and/or procedures for undertaking the competitive bidding process, in addition to the actual implementation of the process.

HECO's 1987 Solicitation of Power Purchase Proposals

After five years of little or no load growth, HECO experienced dramatic load growth from late 1985 through 1986. This led to an unexpected need for additional capacity. HECO's 1986 Generation Resource Plan, which utilized the September 24, 1986 peak load forecast, indicated that a new generating unit would be required by October 1990. HECO determined that the best option for HECO-owned generation, in the absence of any non-utility generating proposals, was to add a new 146 MW oil-fired steam generator at its Kahe Power Plant ("Kahe 7") that would be designed for future conversion to coal.

After HECO issued a Request for Proposals for Engineering Design, Procurement and Construction Management on February 25, 1987, HECO determined that there was significant market interest in the development of non-utility options.

Because of the short lead time available to have additional generation in place by October 1990, HECO pursued alternative ownership options in parallel with its Kahe 7 approach.

With respect to a possible Kahe 7, HECO: (1) awarded a contract to Stone & Webster Engineering Corporation on April 7, 1987 for Kahe 7 engineering services with a "cancellation upon notice clause", (2) filed an application with the Commission for approval of Kahe 7 on April 15, 1987 in Docket No. 5778 (while indicating that alternative methods of financing the project, including non-utility ownership, were being considered), and (3) released requests for bids for turbine and boiler equipment on May 15, 1987 and June 1, 1987, with final bids due on August 3, 1987 and August 21, 1987, respectively. On September 21, 1987, HECO withdrew its application in Docket No. 5778 after it determined that the power purchase alternative was superior.

In order to pursue the power purchase alternative, HECO issued a Purchase Power Alternatives Request for Proposals ("RFP") on June 4, 1987, with a response date of August 17, 1987. In an effort to resolve potential legal impediments to the purchase of power from an independent power producer (or "IPP"), HECO filed an Application for Declaratory Order in Docket No. 5931 on June 23, 1987, and commenced the steps necessary to make a part of the Kahe site available to an IPP. Throughout this period, HECO was assisted in evaluating various non-utility ownership options, including the sale and leaseback option, by its financial consultant, Goldman Sachs.

The RFP was sent to thirty-one interested parties. Seven "serious" bids (with 13 total possible options) were submitted in response to the RFP.

Most of the power purchase proposals were directed at providing a unit substantially identical to the Kahe 7 unit. However, Applied Energy Services, Inc. ("AES") proposed a coal-fired CFB cogeneration unit to be located in the Campbell Industrial Park, coupled with a simple-cycle CT since a coalfired unit could not be brought on line by November 1990. (AES noted that the study filed with HECO's application in Docket No. 5778 recommended a CT as the next unit after Kahe 7.) A second bidder, BBC Brown Boveri, Inc. (also known as Asea Brown Boveri, or "ABB"), proposed a LSFO-fired combined cycle co-generation plant, which also would be located at Campbell Industrial Park. (BBC proposed a partnership, HACOA, to own the project.)

HECO analyzed all of the proposals received on the basis of total revenue requirements. In evaluating the various purchased power bids, HECO's primary objective was to minimize the "all-in" cost of obtaining needed capacity and energy.

HECO also considered technologies, the financial and operating strengths of the bidders, HECO's ability to dispatch the unit(s), scheduling risks, regulatory and legal risks, the system impact of the proposed facilities, and conformity to HECO's terms and conditions. In order to do the evaluation, HECO relied both on its in-house staff and outside consultants, including Management Analysis Company (which assisted in the technical evaluation of the bids and in validating the AES coal pricing), and Goldman Sachs (which assisted in the assessment of the capacity payment structures and the financial strengths of the bidders).

The AES-BP proposal, as bid, proved to be economically superior to the Kahe 7 base case and to the other purchased power alternatives, and AES-BP's use of coal provided HECO with a valuable opportunity to diversify its fuel base on Oahu. The AES-BP proposal offered a very favorable energy price based on coal at a cost of approximately $1.50/mmBtu at a time when HECO was paying about $3.30/mmBtu for low sulphur fuel oil (LSFO). (At the time of the hearings in Docket No. 6177, HECO's LSFO cost was approximately $2.82/mmBtu.)

Because of the even higher then expected load growth experienced by HECO in 1987, HECO determined that it needed both the 180 MW from the BBC combined-cycle facility and the 146 MW from the AES-BP facility. The proposed combined-cycle facility had a higher than expected efficiency and was expected to be very reliable. Moreover, HECO could add 70 MW from the combined-cycle facility as early as 1989. By contracting to purchase power from qualifying cogeneration facilities, the potential legal problems associated with purchasing from IPPs were resolved, and the Application for Declaratory Order was withdrawn on October 2, 1987.

On September 24, 1987, and September 25, 1987, HECO sent letters of intent to BBC and AES.

Subsequently, for the reasons specified in Exhibit A to HECO's Amendment to Application, filed July 29, 1988, in Docket No. 6177, including apparent internal difficulties within the HACOA general partnership, the power purchase agreement between HACOA and HECO was terminated.

Shortly after termination of the HACOA Agreement, HECO met with representatives of ABB to discuss the possible purchase of the proposed HACOA facility and other available options. At that meeting, it was agreed that if a restructuring of the original partnership could be accomplished whereby a subsidiary of ABB would be the sole general partner, HECO's concerns would be alleviated. ABB was subsequently successful in persuading its partners to accept a new limited partnership arrangement and negotiations were opened on a new power purchase agreement between HECO and Kalaeloa (a new limited partnership).

CA-HECO-IR-12 Attachment

RFP/Call for Tenders	Date Initiated	Date RFP Issued	Bids Due	Contract Signed	
Hydro-Quebec Distribution A/O 2002-01 Firm Capacity and Energy 1200 MW	11/15/2000	2/21/2002	6/13/2002	6/10/2003	Call for Tenders Procedures and a Code of Ethics were developed prior prior to the Implementation of the Call for Tenders. The Act Respecting the Regie de l' energie imposes on Hydro-Quebec Distribution the obligation to purchase electricity through Call for Tenders open to all interested bidders, including Hydro-Quebec Production.
Hydro-Quebec Distribution A/O 2003-01 Firm Capacity from Biomass 100 MW	Jan-03	4/15/2003	11/15/2003	Mar-04	Date initiated is approximate time when drafting of the Call for Tenders documents began
Hydro-Quebec Distribution A/O 2003-02 Wind Generated Electricity 1000 MW	Feb-03	5/12/2003	6/15/2004	2/25/2005	Date initiated is approximate time when drafting of the Call for Tenders documents began
Portland General Electric 2003 Request for Proposals	Aug-02	6/18/2003	7/23/2003	Dec-04	The date initiated reflects the date the Company filed its 2002 Integrated Resource Plan
BC Hydro	Aug-03	10/31/2003	8/13/2004	11/19/2004	Date of initiation reflects date in which the Independent Reviewer was retained.
PacifiCorp	1/24/2003	6/6/2003	7/22/2003	11/12/2004	The date initiated reflects the date the Company's IRP was filed. It is not known how much time was required to complete the IRP.

CA-HECO-IR-13

<u>Ref: HECO Companies SOP, Exhibit A at 9.</u>

a. Please provide a status report addressing the development (including milestones achieved) for each of the following facilities:

   1. the "simple cycle peaking unit at Campbell Industrial Park;"

   2. the Maalaea Unit M18;

   3. the Waena Unit 1; and

   4. the Keahole Unit ST-7.

b. For each of the facilities identified above, please indicate whether the relevant electric utility considered meeting its need through a competitive bidding process (i.e., instead of building the identified facility).

c. For each facility regarding which the response to Part (b) is answered in the affirmative, please provide copies of all documents that pertain to the electric utility's decision regarding whether or not to proceed with competitive bidding.

<u>HECO Response:</u>

a.

   1. Campbell Industrial Park Unit 1

      - The application for the air permit was submitted to the Hawaii Department of Health in October 2003.
      - The primary engineering consultant has been hired to develop the conceptual design, cost estimates for the project, and to provide final engineering design services for the project. A permitting consultant has been hired to assist with permitting, including preparing the environmental assessment for the project.
      - In April 2005, a Request for Proposal was sent to the prospective combustion turbine vendors to facilitate selection of the generating unit to be installed. This selection is necessary to support the air permitting and other approval processes,

but does not constitute a commitment of funds to manufacture the equipment.

- Ongoing meetings are being held with the West Oahu neighborhood boards and community leaders to keep them informed of project status and plans.
- An Environmental Impact Statement Preparation Notice was prepared and is scheduled to be submitted to the Office of Environmental Quality Control in May 2005.

2. Maalaea Unit 18

- PUC Decision and Order No. 13730, filed January 11, 1995, in Docket No. 7744, approved MECO's request for the purchase and installation of the Maalaea Dual-Train Combined Cycle No. 2, which included Maalaea Unit 18; an extension of the Special Management Area Use permit was approved by the Maui County Planning Commission on February 11, 2003, and the PSD/CS ("Air") Permit was effective September 8, 2004.
- Major equipment (steam turbine, air-cooled condenser, heat recovery steam generators) have been purchased. Currently specifying auxiliary equipment required for Maalaea 18.
- Construction is forecasted to start in October 2005.
- Commercial Operation date is forecasted for September 2006.

3. Waena 1

- The Final Environmental Impact Statement for the Waena Generating Station was accepted by the Maui County Planning Department in November 1997.
- The application for the air permit was submitted to the Hawaii Department of Health in December 2002.

- A conceptual design of the Waena Generating Station was completed in February 2005.
- Currently, preparing a Request for Proposal for project management, engineering, and start up service to design, construct, and start-up Waena 1, a nominal 20 MW simple cycle combustion turbine.

4. Keahole Unit ST-7

Before Keahole Unit ST-7 is built, the property must be first reclassified from conservation to urban by the County and then rezoned to industrial by the State Land Use Commission (LUC). A petition for reclassification was filed with the LUC in November 2003. An Environmental Impact Statement (EIS) was required and completed for this process. This entire process is not expected to be completed until the first quarter 2007, or later.

The Keahole Final EIS was submitted to the LUC on January 24, 2005. At the Land Use Commission hearing on February 10, 2005, the LUC voted to accept HELCO's Final EIS concerning the land reclassification. The evidentiary hearing dates on the petition for reclassification are set for May 18-19, 2005 and June 1-2, 2005.

b. Competitive bidding was not considered by HECO, MECO and HELCO as an alternative for any of the unit addition projects listed.

c. Not Applicable.

CA-HECO-IR-14

Ref: HECO Companies SOP, Exhibit A at 5.

Please identify (i.e., by soliciting utility, bidder, and RFP date) each instance in which a "bidder was selected as the preferred project, or actually signed a contract and failed to complete the project.

HECO Response:

HECO's consultants can cite two examples of recent cases in which a bidder was selected as the preferred project, decided it could not agree to its original pricing and/or the contracts terms specified in the RFP document and either withdrew its bid, requested to change the pricing and terms of the agreement, or was rejected by the host utility for failure to comply with the stated requirements of the RFP.

In the first example, Hydro-Quebec Distribution Call for Tenders (A/O 2002-01), Calpine Canada was selected for contract award. The Call for Tenders document stated that bidders were required to accept the security provisions stated in the Call for Tenders documents as a condition for submitting their proposal and had to acknowledge acceptance by signing their proposal. Calpine agreed to the requirements by signing its proposal as required. Hydro-Quebec Distribution initiated contract negotiations with Calpine Canada, but subsequently Calpine Canada decided it could not abide by the security terms in the contract. As a result, contract negotiations were terminated and Hydro-Quebec Distribution initiated contract negotiations with the next best project. Hydro-Quebec Distribution eventually completed a contract with this bidder. The contract was signed several months after the estimated completion date due to the time lost in the negotiation process with the initial project.

A second example is Central Power & Lights' (CPL) 1997 Supply-side RFP. A bidder (confidential) was selected as the winning bidder and contacted by CPL to begin contract negotiations. Shortly after contract negotiations began, the bidder terminated negotiations, claiming its price was too low to complete the project. Since the RFP stated that price was not negotiable, CPL decided to begin negotiations with the next best bidder. Negotiations with the second bidder began and several sessions were held. During the negotiations process, the bidder informed CPL that it could not abide by the guaranteed availability included in its proposal because its generation equipment manufacturer could no longer guarantee the availability level proposed. After assessing the economic impact of a lower guaranteed availability level, CPL decided to terminate contract negotiations with this bidder as well.

In addition, MECO and HELCO have experienced situations where it signed a contract with an Independent Power Producer, and the projects were never completed.

On August 17, 1999, following negotiations between the parties, HELCO signed a Power Purchase Contract (Contract) with Kahua Power Partners LLC (KPP) for 10 MW of as-available energy from a wind farm at Kahua Ranch, Hawaii. The Contract was amended by Amendment No. 1 on April 4, 2000, and the Contract and Amendment No. 1 (Amended Contract) were approved by the Commission in Docket No. 00-0177 on June 1, 2001. The Amended Contract was assigned to Hawi Renewable Development (HRD) on September 12, 2003. On November 25, 2003, HRD informed HELCO that it did not intend to pursue the construction of the wind farm project at Kahua Ranch because it intended to pursue its separate, expanded wind project at Hawi, and requested that HELCO terminate the Amended Contract. HELCO consented to termination by letter dated December 9, 2003, and filed notice of the termination letter with the Commission on January 20, 2004 in Docket No. 00-0177.

On June 17, 1985, following negotiations between the parties, MECO signed a Power Purchase Contract (Contract) with Zond Pacific, Inc. (Zond) for 10 MW of as-available energy from a wind farm at Kaanapali, Maui. The Contract was approved by the Commission in Docket No. 5324 on July 17, 1985. On June 29, 1989, Zond requested changes to the Contract because it felt that "the project would have a very limited chance of implementation since the contract terms simply are not adequate enough to attract the necessary institutional financing within the time frame provided." After considering Zond's proposals for changes to the Contract, MECO determined that it could not agree to these changes. By letter dated October 12, 1989, MECO terminated the Contract, and suggested that Zond enter into a new contract when they have a more firm and realistic operational date.

CA-HECO-IR-15

Re: HECO Companies SOP, Exhibit A at 5.

Please identify (i.e., by soliciting utility, bidder, and RFP date) each instance in which a developer walked away from a partially or nearly completed project.

HECO Response:

There have been several recent examples of instances in which a developer has walked away from a partially or nearly completed project (or fully operational projects). An article by Platts entitled "Banks Hold 14,065 MW of Merchant Assets as a Result of Defaults by Four Companies" 2/25/2004, provides several examples of such cases. (www.platts.com/Magazines/Platts%20T&D/News%20Archive/022504_8.xml)

As noted in the article, National Energy Group (NEG), the merchant division of PG&E Corp., defaulted on $2.3 billion in loans and credit facilities and $605-million in equity guarantees covering eight generating facilities. Three generating plants: (1) the Athens facility in Athens New York (1,080 MW); (2) the Covert plant in Covert, Michigan (1,200 MW); and (3) the Harquahala plant in Tonopah, Arizona (1,175 MW) were under construction at the time of bankruptcy.

Exelon Corp. also walked away from its equity stake in six units owned by its Boston Generating LLC subsidiary, which was created from its acquisition of former Sithe Energies' holdings. Two plants: (1) the Mystic combined cycle units (1,600 MW) and (2) the Fore River facility (800 MW) were both nearly completed at the time Excelon walked away.

Another example is El Paso walking away from its investment in the Milford, Connecticut project (544 MW) on December 31, 2003.

Also, please refer to the response to CA-HECO-IR-14 for examples of projects in which the developer failed to complete a specific project.

CA-HECO-IR-16

Re: HECO Companies SOP, Exhibit A at 6.

a. Please state the HECO Companies' view regarding whether the "obligation to serve:"

    1. can be imputed by an electric utility to some other entity; or

    2. should be imputed, perhaps by the Commission, to another entity.

b. Are the HECO Companies aware of any circumstances under which the obligation to serve (i.e., for an electric utility to provide reliable service) can reside within an entity other than an electric utility under Hawaii Law or Commission practice?

c. If yes, please identify such circumstances and explain the basis for the Company's assertion.

HECO Response:

a. In general, a utility would not be able to "assign" its obligation to serve and, thus, be relieved of its obligation to serve (absent regulatory restructuring). The Commission may or may not be able to impose obligations on non-utilities as a condition for approving certain contracts (but the obligations would contractual, and not a result of the non-utility's status. (PURPA and state law specifically exclude certain forms of utility-type regulation for QFs and non-fossil fuel producers. Also, the Commission has found that IPPs that sell solely to utilities are not utilities themselves.) Also, as a practical matter, the imposition of utility obligations on power producers and/or broad requirements that such power producers indemnify utilities for their inability to fulfill their obligation to serve may render projects unfinanceable.

b. In states that have implemented retail access for utility customers, the utilities have the obligation to deliver power but not the obligation to supply generation service. Since utilities in many of these states sold their generation assets, the obligation to provide generation service is no longer applicable. However, most utilities still provide some form of standard offer or default service for customers who have chosen not to secure their own supply service.

Hawaii has not implemented such a restructuring process as other states. Thus, HECO, HELCO and MECO still have the obligation to serve customer requirements.

c. Not applicable.

CA-HECO-IR-17

<u>Ref: Exhibit E.</u>

For each state "bidding status" provided, please provide:

a. a citation to the source document for all information included; and

b. a copy of each cited document where such document is not readily available (<u>e.g.</u>, on a publicly accessible internet web-page).

<u>HECO Response:</u>

a. Two source documents were used as a starting point for Exhibit E. The first is Table A-1 from Attachment B of HECO's Position Statement for the Electric Competition Proceeding in Docket No. 96-0493, which was prepared by HECO's consultant, and which reflects the information on the status of competitive bidding in each state from a report by the National Regulatory Research Institute entitled <u>State Commission Regulations of Self-Dealing Power Transactions,</u> January 1996.

The second source document is from the US Department of Energy Energy Information Administration's website (<u>www.eia.doe.gov</u>). The website (under electricity) contains an update on electric industry restructuring by state as of February 2003, along with a description of electric restructuring and retail access activity in each state.

HECO's consultant also made adjustments, as appropriate, based on on-going activities associated with competitive bidding in select states as a result of participation in competitive bidding processes. HECO's consultant has worked with utilities and others in competitive bidding assignments in the following states: Maine, Massachusetts, New York, New Jersey, Delaware, Maryland, North Carolina, South Carolina, Illinois, Minnesota, Wisconsin, Oklahoma, Texas, Arkansas, Louisiana, Utah, and Oregon, as well as following competitive bidding activities in a number of other states.

b. Please refer to website reference for the US Department of Energy, Energy Information Administration website. The report identified from the National Regulatory Research Institute is available from NRRI (www.nrri.Ohio-State.edu). (HECO's consultant no longer has a copy of the NRRI report.)

CA-HECO-IR-18

Ref: HECO Companies SOP, Exhibit A at 9.

The HECO Companies include the "long lead time for environmental review, permitting and approvals" as among the constraints in using competitive bidding to respond to near-term needs for incremental capacity resources. Please state all instances (i.e., as known to HECO or its consultants) in which state environmental review processes were accelerated to address an immediate or near-term need for incremental capacity resources.

HECO Response:

It is HECO understanding that in February 2001, California Governor Davis signed Executive Orders to expedite the review and permitting process of power generating facilities in California while maintaining environmental standards. See the following link for additional information:

http://www.arb.ca.gov/energy/energy.htm

However, HECO is uncertain if these Executive Orders actually resulted in permit approvals being accelerated.

CA-HECO-IR-19

<u>Ref: HECO Companies SOP, Exhibit A at 24.</u>
The text states that "the HECO Companies have already been required by the credit rating agencies to rebalance their capital structures as a result of their purchased power commitments." Please provide a copy of all documents received from "credit rating agencies" that imposed this requirement on the HECO Companies.

<u>HECO Response:</u>

As discussed by the return on rate base witness in HECO's current rate case (HECO T-21 in Docket No. 04-0113), HECO must maintain at least its current credit rating in order to maintain continuous access to capital markets. As indicated in the SOP, the credit rating agencies have determined that certain obligations of the Company that are not currently reported as liabilities on the Company's balance sheet should be reflected as debt in the ratios used to evaluate the Company's risk profile. In order to capture the risks associated with these obligations, the credit rating agencies calculate "imputed debt." The S&P article "'Buy Versus Build': Debt Aspects of Purchased-Power Agreements" (pages 3-7) provides a description of S&P's methodology for imputing debt and interest expense. This article has also been provided in Docket No. 04-0113 as Exhibit HECO-2111. The S&P method of imputing debt for purchase power is explained in detail in HECO's current rate case (HECO T-21, pages 26-27, in Docket No. 04-0113).

Credit ratings are determined based on an evaluation of both qualitative and quantitative measures. The S&P article "New Business Profile Scores Assigned for U.S. Utility and Power Companies; Financial Guidelines Revised" (attached pages 8-26) discusses indicative credit ratings for three key financial ratios: 1) funds from operations/interest coverage, 2) funds from operations/total debt, and 3) total debt/total equity. Imputed debt and imputed interest expense negatively impact all three ratios. In its published credit evaluations of HECO (for example, see

S&P RatingsDirect Hawaiian Electric Company, Inc. dated December 13, 2004 attached on pages 27-29), S&P has indicated that it takes imputed debt and interest expense relating to HECO's purchase power contracts into account in evaluating its financial ratios.

In the early 1990's, HECO's credit rating was downgraded, in part as a result of the risks associated with the purchase power contracts it signed in the late 1980's. Also in the early 1990's, S&P developed its methodology for taking the risks of purchase power into consideration in evaluating a company's credit. As a result, HECO increased its equity ratio in order to improve its key financial ratios. In past discussions with S&P, they have indicated that a downgrading was eminent unless HECO could improve its key financial ratios; however, no written correspondence was provided.

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"Buy Versus Build": Debt Aspects of Purchased-Power Agreements

Credit Analysts: Jeffrey Wolinsky, CFA, New York (1) 212-438-2117; Dimitri Nikas, New York (1) 212-438-7807; Anthony Flintoff, London (44) 20-7826-3874; Laurie Conheady, Melbourne (61) 3-9631-2036

Standard & Poor's Ratings Services views electric utility purchased-power agreements (PPA) as debt-like in nature, and has historically capitalized these obligations on a sliding scale known as a "risk spectrum." Standard & Poor's applies a 0% to 100% "risk factor" to the net present value (NPV) of the PPA capacity payments, and designates this amount as the debt equivalent.

While determination of the appropriate risk factor takes several variables into consideration, including the economics of the power and regulatory treatment, the overwhelming factor in selecting a risk factor has been a distinction in the likelihood of payment by the buyer. Specifically, Standard & Poor's has divided the PPA universe into two broad categories: take-or-pay contracts (TOP; hell or high water) and take-and-pay contracts (TAP; performance based). To date, TAP contracts have been treated far more leniently (e.g., a lower risk factor is applied) than TOP contracts since failure of the seller to deliver energy, or perform, results in an attendant reduction in payment by the buyer. Thus, TAP contracts were deemed substantially less debt-like. In fact, the risk factor used for many TAP obligations has been as low as 5% or 10% as opposed to TOPs, which have been typically at least 50%.

Standard & Poor's originally published its purchased-power criteria in 1990, and updated it in 1993. Over the past decade, the industry underwent significant changes related to deregulation and acquired a history with regard to the performance and reliability of third-party generators. In general, independent generation has performed well; the likelihood of nondelivery--and thus release from the payment obligation--is low. As a result, Standard & Poor's believes that the distinction between TOPs and TAPs is minimal, the result being that the risk factor for TAPs will become more stringent. This article reiterates Standard & Poor's views on purchased power as a fixed obligation, how to quantify this risk, and the credit ramifications of purchasing power in light of updated observations.

Why Capitalize PPAs?

Standard & Poor's evaluates the benefits and risks of purchased power by adjusting a purchasing utility's reported financial statements to allow for more meaningful comparisons with utilities that build generation. Utilities that build typically finance construction with a mix of debt and equity. A utility that leases a power plant has entered into a debt transaction for that facility; a capital lease appears on the utility's balance sheet as debt. A PPA is a similar fixed commitment. When a utility enters into a long-term PPA with a fixed-cost component, it takes on financial risk. Furthermore, utilities are typically not financially compensated for the risks they assume in purchasing power, as purchased power is usually recovered dollar-for-dollar as an operating expense.

As electricity deregulation has progressed in some countries, states, and regions, the line has blurred between traditional utilities, vertically integrated utilities, and merchant energy companies, all of which are in the generation business. A common contract that has emerged is the tolling agreement, which gives an energy merchant company the right to purchase power from a specific power plant. (see "Evaluating Debt Aspects of Power Tolling Agreements," published Aug. 26, 2002). The energy merchant, or toller, is typically responsible for procuring and delivering gas to the plant when it wants the plant to generate power. The power plant operator must maintain plant availability and produce electricity at a contractual heat rate. Thus, tolling contracts exhibit characteristics of both PPAs and leases. However, tollers are typically unregulated entities competing in a competitive marketplace. Standard & Poor's has determined that a 70% risk factor should be applied to the NPV of the fixed tolling payments, reflecting its assessment of the risks borne by the toller, which are:

- Fixed payments that cover debt financing of power plant (typically highly leveraged at about 70%),
- Commodity price of inputs,
- Energy sales (price and volume), and
- Counterparty risk.

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Determining the Risk Factor for PPAs

Alternatively, most entities entering into long-term PPAs, as an alternative to building and owning power plants, continue to be regulated utilities. Observations over time indicate the high likelihood of performance on TAP commitments and, thus, the high likelihood that utilities must make fixed payments. However, Standard & Poor's believes that vertically integrated, regulated utilities are afforded greater protection in the recovery of PPAs, compared with the recovery of fixed tolling charges by merchant generators. There are two reasons for this. First, tariffs are typically set by regulators to recover costs. Second, most vertically integrated utilities continue to have captive customers and an obligation to serve. At a minimum, purchased power, similar to capital costs and fuel costs, is included in tariffs as a cost of service.

As a generic guideline for utilities with PPAs included as an operating expense in base tariffs, Standard & Poor's believes that a 50% risk factor is appropriate for long-term commitments (e.g. tenors greater than three years). This risk factor assumes adequate regulatory treatment, including recognition of the PPA in tariffs; otherwise a higher risk factor could be adopted to indicate greater risk of recovery. Standard & Poor's will apply a 50% risk factor to the capacity component of both TAP and TOP PPAs. Where the capacity component is not broken out separately, we will assume that 50% of the payment is the capacity payment. Furthermore, Standard & Poor's will take counterparty risk into account when considering the risk factor. If a utility relies on any individual seller for a material portion of its energy needs, the risk of nondelivery will be assessed. To the extent that energy is not delivered, the utility will be exposed to replacing this power, potentially at market rates that could be higher than contracted rates and potentially not recoverable in tariffs.

Standard & Poor's continues to view the recovery of purchased-power costs via a fuel-adjustment clause, as opposed to base tariffs, as a material risk mitigant. A monthly or quarterly adjustment mechanism would ensure dollar-for-dollar recovery of fixed payments without having to receive approval from regulators for changes in fuel costs. This is superior to base tariff treatment, where variations in volume sales could result in under-recovery if demand is sluggish or contracting. For utilities in supportive regulatory jurisdictions with a precedent for timely and full cost recovery of fuel and purchased-power costs, a risk factor of as low as 30% could be used. In certain cases, Standard & Poor's may consider a lower risk factor of 10% to 20% for distribution utilities where recovery of certain costs, including stranded assets, has been legislated. Qualifying facilities that are blessed by overarching federal legislation may also fall into this category. This situation would be more typical of a utility that is transitioning from a vertically integrated to a disaggregated distribution company. Still, it is unlikely that no portion of a PPA would be capitalized (zero risk factor) under any circumstances.

The previous scenarios address how purchased power is quantified for a vertically integrated utility with a bundled tariff. However, as the industry transitions to disaggregation and deregulation, various hybrid models have emerged. For example, a utility can have a deregulated merchant energy subsidiary, which buys power and off-sells it to the regulated utility. The utility in turn passes this power through to customers via a fuel-adjustment mechanism. For the merchant entity, a 70% risk factor would likely be applied to such a TAP or tolling scheme. But for the utility, a 30% risk factor would be used. What would be the appropriate treatment here? In part, the decision would be driven by the ratings methodology for the family of companies. Starting from a consolidated perspective, Standard & Poor's would use a 30% risk factor to calculate one debt equivalent on the consolidated balance sheet given that for the consolidated entity the risk of recovery would ultimately be through the utility's tariff. However, if the merchant energy company were deemed noncore and its rating was more a reflection of its stand-alone creditworthiness, Standard & Poor's would impute a debt equivalent using a 70% risk factor to its balance sheet, as well as a 30% risk-adjusted debt equivalent to the utility. Indeed, this is how the purchases would be reflected for both companies if there were no ownership relationship. This example is perhaps overly simplistic because there will be many variations on this theme. However, Standard & Poor's will apply this logic as a starting point, and modify the analysis case-by-case, commensurate with the risk to the various participants.

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Adjusting Financial Ratios

Standard & Poor's begins by taking the NPV of the annual capacity payments over the life of the contract. The rationale for not capitalizing the energy component, even though it is also a nondiscretionary fixed payment, is to equate the comparison between utilities that buy versus build--i.e., Standard & Poor's does not capitalize utility fuel contracts. In cases where the capacity and energy components of the fixed payment are not specified, half of the fixed payment is used as a proxy for the capacity payment. The discount rate is 10%. To determine the debt equivalent, the NPV is multiplied by the risk factor. The resulting amount is added to a utility's reported debt to calculate adjusted debt. Similarly, Standard & Poor's imputes an associated interest expense equivalent of 10%--10% of the debt equivalent is added to reported interest expense to calculate adjusted interest coverage ratios. Key ratios affected include debt as a percentage of total capital, funds from operations (FFO) to debt, pretax interest coverage, and FFO interest coverage. Clearly, the higher the risk factor, the greater the effect on adjusted financial ratios. When analyzing forecasts, the NPV of the PPA will typically decrease as the maturity of the contract approaches.

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Utility Company Example

To illustrate some of the financial adjustments, consider the simple example of ABC Utility Co. buying power from XYZ Independent Power Co. Under the terms of the contract, annual payments made by ABC Utility start at $90 million in 2003 and rise 5% per year through the contract's expiration in 2023. The NPV of these obligations over the life of the contract discounted at 10% is $1.09 billion. In ABC's case, Standard & Poor's chose a 30% risk factor, which when multiplied by the obligation results in $327 million. Table 1 illustrates the adjustment to ABC's capital structure, where the $327 million debt equivalent is added as debt, causing ABC's total debt to capitalization to rise to 59% from 54% (11 plus 48). Table 2 shows that ABC's pretax interest coverage was 2.6x, without adjusting for off-balance-sheet obligations. To adjust for the XYZ capacity payments, the $327 million debt adjustment is multiplied by a 10% interest rate to arrive at about $33 million. When this amount is added to both the numerator and the denominator, adjusted pretax interest coverage falls to 2.3x.

Table 1 ABC Utility Co. Adjustment to Capital Structure

	Original capital structure		Adjusted capital structure	
	$	%	$	%
Debt	1,400	54	1,400	48
Adjustment to debt	-	-	327	11
Preferred stock	200	8	200	7
Common equity	1,000	38	1,000	34
Total capitalization	2,600	100	2,927	100

Table 2 ABC Utility Co. Adjustment to Pretax Interest Coverage

		Original pretax interest coverage (x)		Adjusted pretax interest coverage (x)	
Net income	120				
Income taxes	65	300		(300+33)	
Interest expense	115	115	= 2.6x	(115+33)	= 2.3x
Pretax available	300				

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Credit Implications

The credit implications of the updated criteria are that Standard & Poor's now believes that historical risk factors applied to TAP contracts with favorable recovery mechanisms are insufficient to capture the financial risk of these fixed obligations. Indeed, in many cases where 5% and 10% risk factors were applied, the change in adjusted financial ratios (from unadjusted) was negligible and had no effect on ratings. Standard & Poor's views the high probability of energy delivery and attendant payment warrants recognition of a higher debt equivalent when capitalizing PPAs. Standard & Poor's will attempt to identify utilities that are more vulnerable to modifications in purchased-power adjustments. Utilities can offset these financial adjustments by recognizing purchased power as a debt equivalent, and incorporating more common equity in their capital structures. However, Standard & Poor's is aware that utilities have been reluctant to take this action because many regulators will not recognize the necessity for, and authorize a return on, this additional wedge of common equity. Alternatively, regulators could authorize higher returns on existing common equity or provide an incentive return mechanism for economic purchases. Notwithstanding unsupportive regulators, the burden will still fall on utilities to offset the financial risk associated with purchases by either qualitative or quantitative means.

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STANDARD & POOR'S UTILITIES

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New Business Profile Scores Assigned for U.S. Utility and Power Companies; Financial Guidelines Revised

Credit Analysts: Ronald M Barone, New York (1) 212-438-7662; Richard W Cortright, Jr. , New York (1) 212-438-7665; Suzanne G Smith, New York (1) 212-438-2106; John W Whitlock, New York (1) 212-438-7678; Andrew Watt, New York (1) 212-438-7868; Arthur F Simonson, New York (1) 212-438-2094

Standard & Poor's Ratings Services has assigned new business profile scores to U.S. utility and power companies to better reflect the relative business risk among companies in the sector. Standard & Poor's also has revised its published risk-adjusted financial guidelines. The new business scores and financial guidelines do not represent a change to Standard & Poor's ratings criteria or methodology, and no ratings changes are anticipated from the new business profile scores or revised financial guidelines.

New Business Profile Scores and Revised Financial Guidelines

Standard & Poor's has always monitored changes in the industry and altered its business risk assessments accordingly. This is the first time since the 10-point business profile scale for U.S. investor-owned utilities was implemented that a comprehensive assessment of the benefits and the application of the methodology has been made. The principal purpose was to determine if the methodology continues to provide meaningful differentiation of business risk. The review indicated that while business profile scoring continues to provide analytical benefits, the complete range of the 10-point scale was not being utilized to the fullest extent.

Standard & Poor's has also revised the key financial guidelines that it uses as an integral part of evaluating the credit quality of U.S. utility and power companies. These guidelines were last updated in June 1999. The financial guidelines for three principal ratios (funds from operations (FFO) interest coverage, FFO to total debt, and total debt to total capital) have been broadened so as to be more flexible. Pretax interest coverage as a key credit ratio was eliminated.

Finally, Standard & Poor's has segmented the utility and power industry into sub-sectors based on the dominant corporate strategy that a company is pursuing. Standard & Poor's has published a new U.S. utility and power company ranking list that reflects these sub-sectors.

There are numerous benefits to the reassessment. Fuller utilization of the entire 10-point scale provides a superior relative ranking of qualitative business risk. A simultaneous revision of the financial guidelines supports the goal of not causing rating changes from the recalibration of the business profiles. Classification of companies by sub-sectors will ensure greater comparability and consistency in ratings. The use of industry segmentation will also allow more in-depth statistical analysis of ratings distributions and rating changes.

The reassessment does not represent a change to Standard & Poor's criteria or methodology for determining ratings for utility and power companies. Each business profile score should be considered as the assignment of a new score; these scores do not represent improvement or deterioration in our assessment of an individual company's business risk relative to the previously assigned score. The financial guidelines continue to be risk-adjusted based on historical utility and industrial medians. Segmentation into industry sub-sectors does not imply that specific company characteristics will not weigh heavily into the assignment of a company's business profile score.

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Results

Previously, 83% of U.S. utility and power business profile scores fell between '3' and '6', which clearly does not reflect the risk differentiation that exists in the utility and power industry today. Since the 10-point scale was introduced, the industry has transformed into a much less homogenous industry, where the divergence of business risk--particularly regarding management, strategy, and degree of competitive market exposure--has created a much wider spectrum of risk profiles. Yet over the same period, business profile scores actually converged more tightly around a median score of '4'. The new business profile scores, as of the date of this publication, are shown in Chart 1. The overall median business profile score is now '5'.

Chart 1

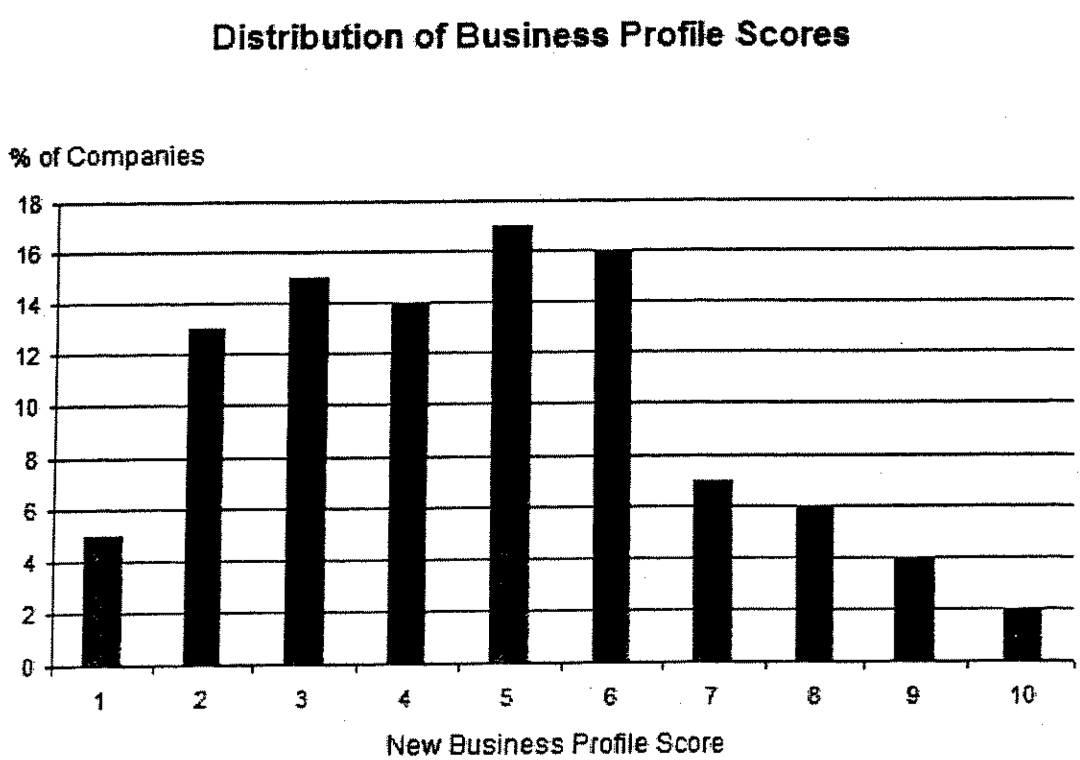

Table 1 contains the revised financial guidelines. It is important to emphasize that these metrics are only guidelines associated with expectations for various rating levels. Although credit ratio analysis is an important part of the ratings process, these three statistics are by no means the only critical financial measures that Standard & Poor's uses in its analytical process. We also analyze a wide array of financial ratios that do not have published guidelines for each rating category.

Table 1 Revised Financial Guidelines

Funds from operations/interest coverage (x)

Business Profile	AA		A		BBB		BB	
1	3	2.5	2.5	1.5	1.5	1		
2	4	3	3	2	2	1		
3	4.5	3.5	3.5	2.5	2.5	1.5	1.5	1
4	5	4.2	4.2	3.5	3.5	2.5	2.5	1.5
5	5.5	4.5	4.5	3.8	3.8	2.8	2.8	1.8
6	6	5.2	5.2	4.2	4.2	3	3	2
7	8	6.5	6.5	4.5	4.5	3.2	3.2	2.2
8	10	7.5	7.5	5.5	5.5	3.5	3.5	2.5
9			10	7	7	4	4	2.8
10			11	8	8	5	5	3

Funds from operation/total debt (%)

Business Profile	AA		A		BBB		BB	
1	20	15	15	10	10	5		
2	25	20	20	12	12	8		
3	30	25	25	15	15	10	10	5
4	35	28	28	20	20	12	12	8
5	40	30	30	22	22	15	15	10
6	45	35	35	28	28	18	18	12
7	55	45	45	30	30	20	20	15
8	70	55	55	40	40	25	25	15
9			65	45	45	30	30	20
10			70	55	55	40	40	25

Total debt/total capital (%)

Business Profile	AA		A		BBB		BB	
1	48	55	55	60	60	70		
2	45	52	52	58	58	68		
3	42	50	50	55	55	65	65	70
4	38	45	45	52	52	62	62	68
5	35	42	42	50	50	60	60	65

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6	32	40	40	48	48	58	58	62
7	30	38	38	45	45	55	55	60
8	25	35	35	42	42	52	52	5
9			32	40	40	50	50	55
10			25	35	35	48	48	52

Again, ratings analysis is not driven solely by these financial ratios, nor has it ever been. In fact, the new financial guidelines that Standard & Poor's is incorporating for the specified rating categories reinforce the analytical framework whereby other factors can outweigh the achievement of otherwise acceptable financial ratios. These factors include:

- Effectiveness of liability and liquidity management;
- Analysis of internal funding sources;
- Return on invested capital;
- The record of execution of stated business strategies;
- Accuracy of projected performance versus actual results, as well as the trend;
- Assessment of management's financial policies and attitude toward credit; and
- Corporate governance practices.

Charts 2 through 6 show business profile scores broken out by industry sub-sector. The five industry sub-sectors are:

- Transmission and distribution--Water, gas, and electric;
- Transmission only--Electric, gas, and other;
- Integrated electric, gas, and combination utilities;
- Diversified energy and diversified nonenergy; and
- Energy merchant/power developer/trading and marketing companies.

Chart 2

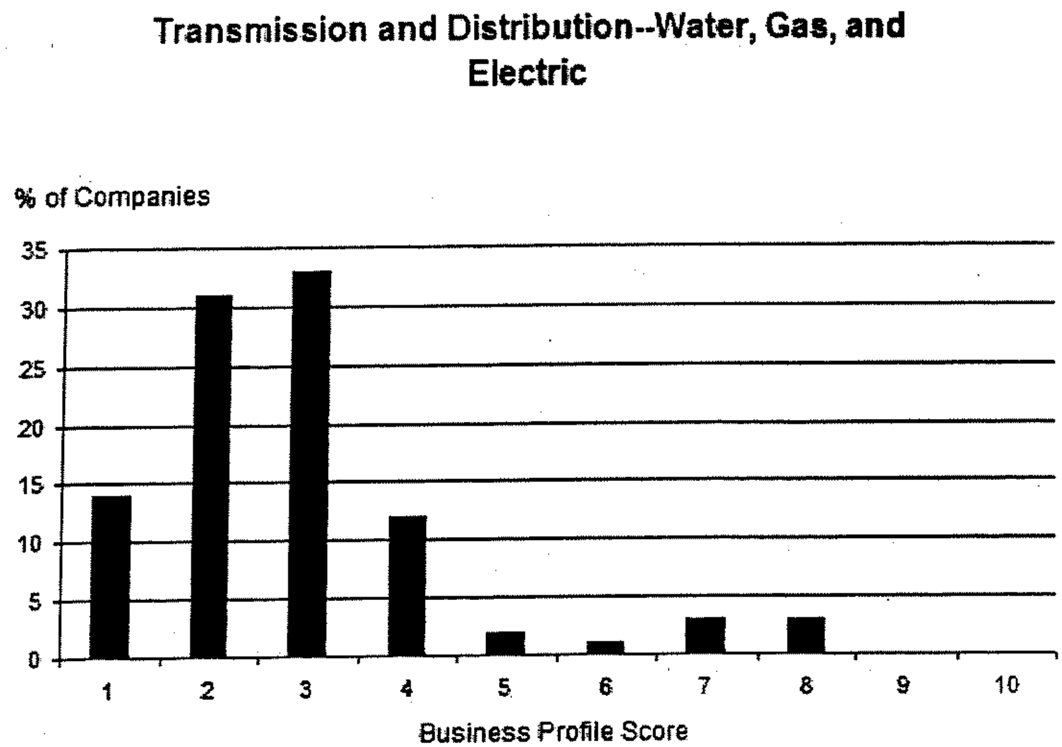

Transmission and Distribution--Water, Gas, and Electric
% of Companies
35
30
25
20
15
10
5
0
1
2
3
4
5
6
7
8
9
10
Business Profile Score

Chart 3

Transmission Only--Electric, Gas, and Other

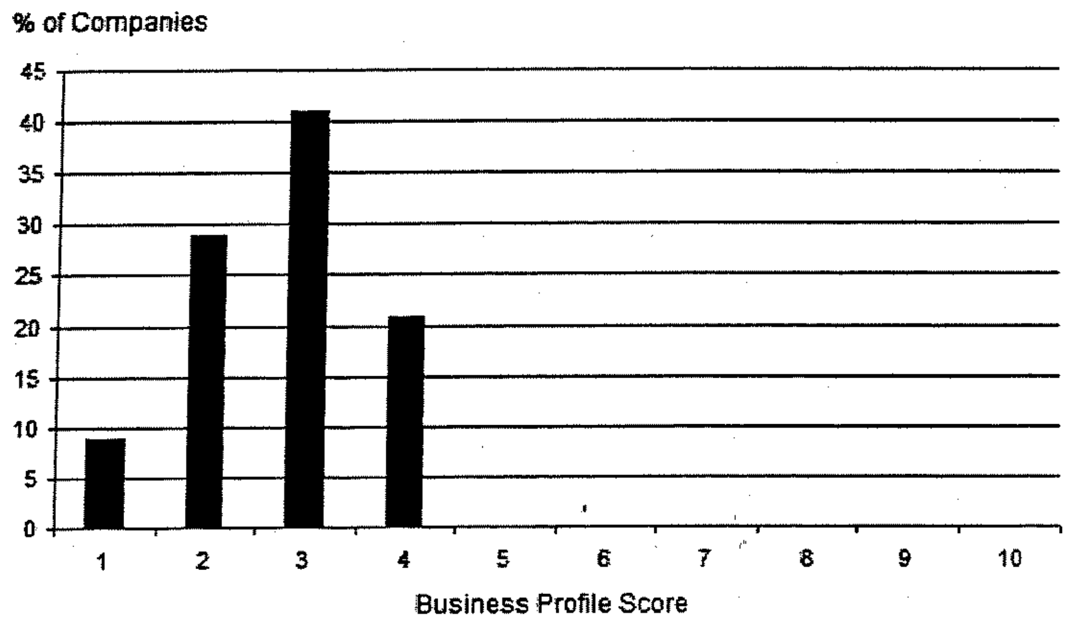


Chart 4

Integrated Electric, Gas, and Combination Utilities

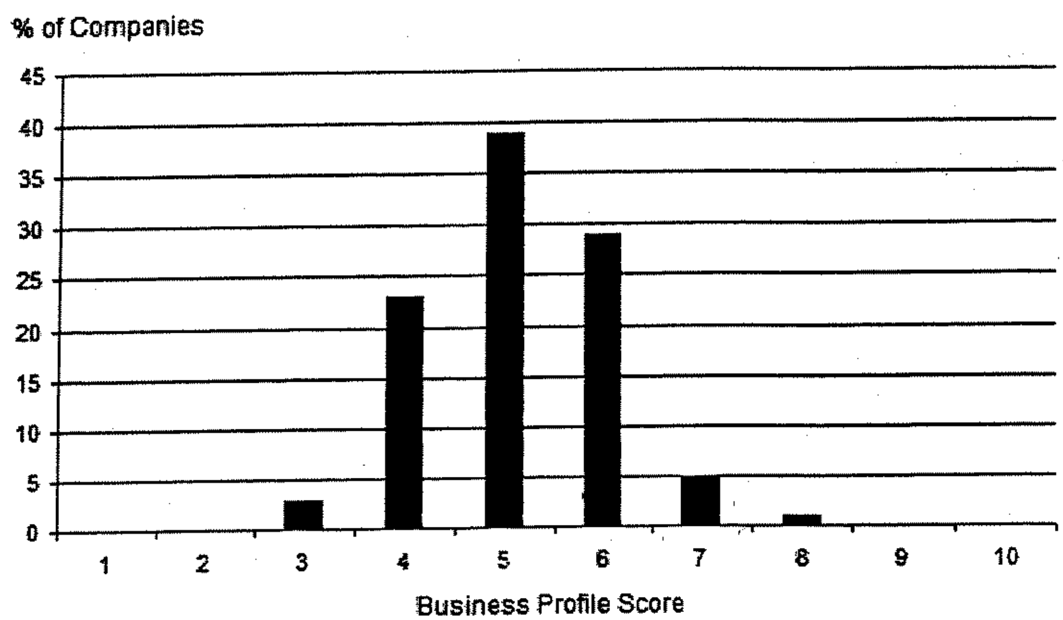


Chart 5

Diversified Energy and Diversified Non-Energy

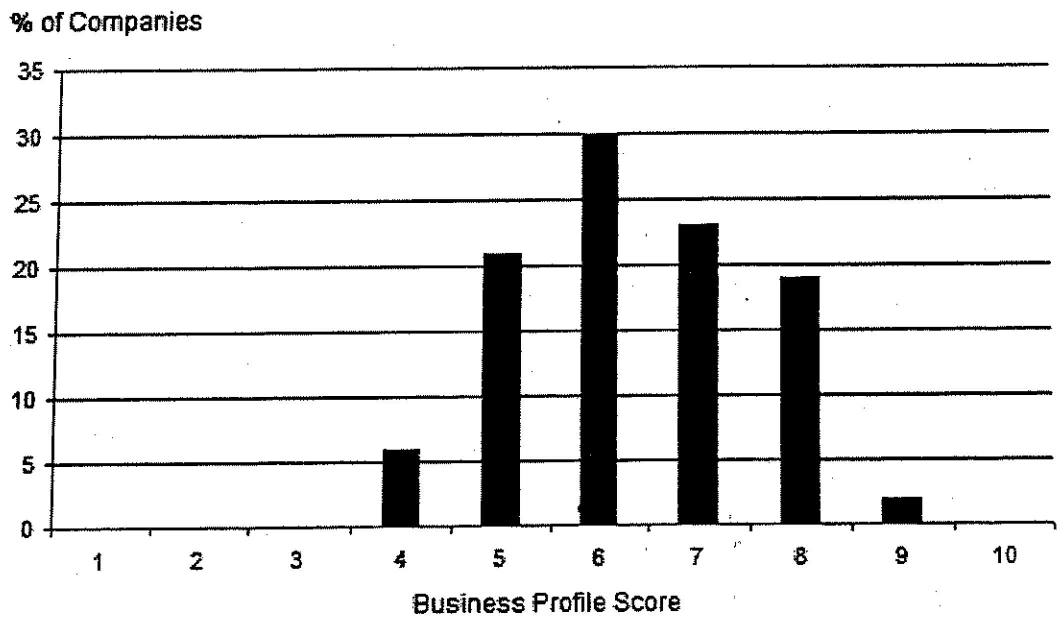
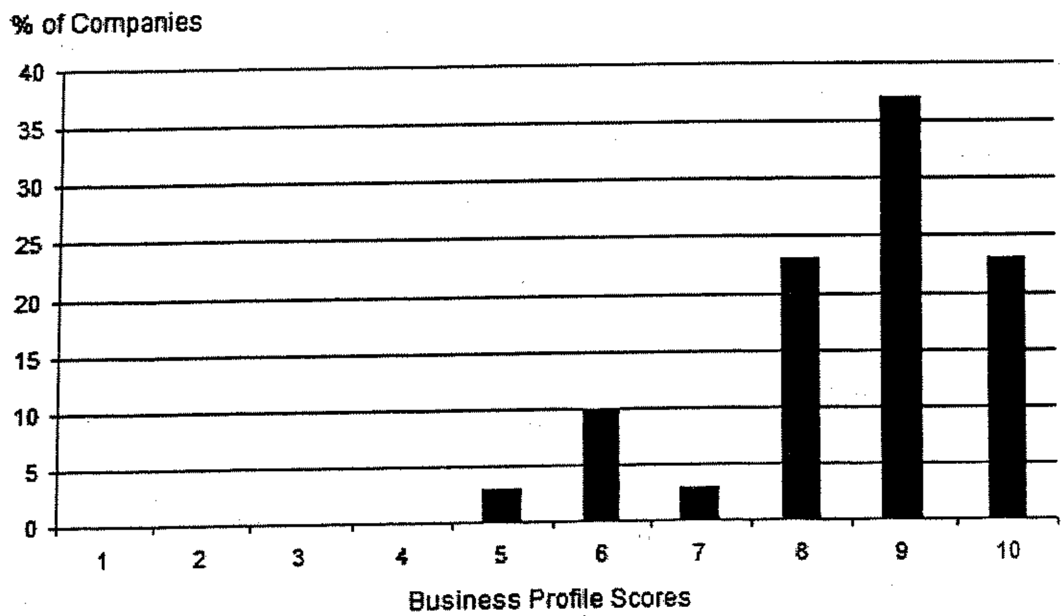


Chart 6

Energy Merchant/Developers/Trading and Marketing



The average business profile scores for transmission and distribution companies and transmission-only companies are lower on the scale than the previous averages, while the average business profile scores for integrated utilities, diversified energy, and energy merchants and developers are higher.

The Appendix provides the company list of business profile scores segmented by industry sub-sector and ranked in order of credit rating, outlook, business profile score, and relative strength.

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Business Profile Score Methodology

Standard & Poor's methodology of determining corporate utility business risk is anchored in the assessment of certain specific characteristics that define the sector. We assign business profile scores to each of the rated companies in the utility and power sector on a 10-point scale, where '1' represents the lowest risk and '10' the highest risk. Business profile scores are assigned to all rated utility and power companies, whether they are holding companies, subsidiaries or stand-alone corporations. For operating subsidiaries and stand-alone companies, the score is a bottom-up assessment. Scores for families of companies are a composite of the operating subsidiaries' scores. The actual credit rating of a company is analyzed, in part, by comparing the business profile score with the risk-adjusted financial guidelines.

For most companies, business profile scores are assessed using five categories; specifically, regulation, markets, operations, competitiveness, and management. The emphasis placed on each category may be influenced by the dominant strategy of the company or other factors. For example, for a regulated transmission and distribution company, regulation may account for 30% to 40% of the business profile score because regulation can be the single-most important credit driver for this type of company. Conversely, competition, which may not exist for a transmission and distribution company, would provide a much lower proportion (e.g., 5% to 15%) of the business profile score.

For certain types of companies, such as power generators, power developers, oil and gas exploration and production companies, or nonenergy-related holdings, where these five components may not be appropriate, Standard & Poor's will use other, more appropriate methodologies. Some of these companies are assigned business profile scores that are useful only for relative ranking purposes.

As noted above, the business profile score for a parent or holding company is a composite of the business profile scores of its individual subsidiary companies. Again, Standard & Poor's does not apply rigid guidelines for determining the proportion or weighting that each subsidiary represents in the overall business profile score. Instead, it is determined based on a number of factors. Standard & Poor's will analyze each subsidiary's contribution to FFO, forecast capital expenditures, liquidity requirements, and other parameters, including the extent to which one subsidiary has higher growth. The weighting is determined case-by-case.

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Appendix: U.S. Utility and Power Company Ranking List

U.S. Utility and Power Company Ranking List		
Company	**Corporate Credit Rating**	**Business Profile**
1. Regulated Transmission and Distribution - Electric, Gas, and Water		
Baton Rouge Water Works Co. (The)	AA/Stable/--	1
Nicor Gas Co.	AA/Stable/A-1+	2
Nicor Inc.	AA/Stable/A-1+	3
Washington Gas Light Co.	AA-/Stable/A-1+	2
WGL Holdings Inc.	AA-/Stable/A-1+	3
New Jersey Natural Gas Co.	A+/Stable/A-1	1
Aqua Pennsylvania	A+/Stable/--	2
KeySpan Energy Delivery Long Island	A+/Negative/--	1
KeySpan Energy Delivery New York	A+/Negative/--	1
Elizabethtown Water Co.	A+/Negative/--	2
California Water Service Co.	A+/Negative/--	3
Questar Gas Co.	A+/Negative/--	3
Southern California Gas Co.	A/Stable/A-1	1
Boston Edison Co.	A/Stable/A-1	1

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Commonwealth Electric Co.	A/Stable/--	1
Cambridge Electric Light Co.	A/Stable/--	1
NSTAR	A/Stable/A-1	1
Massachusetts Electric Co.	A/Stable/A-1	1
Narragansett Electric Co.	A/Stable/A-1	1
Northwest Natural Gas Co.	A/Stable/A-1	1
Connecticut Water Service Inc.	A/Stable/ --	2
Connecticut Water Co. (The)	A/Stable/ --	2
Aquarion Co.	A/Stable/--	2
Aquarion Water Co. of Connecticut	A/Stable/--	2
NSTAR Gas Co.	A/Stable/--	2
Piedmont Natural Gas Co. Inc.	A/Stable/A-1	2
National Grid USA	A/Stable/A-1	2
Consolidated Edison Co. of New York Inc.	A/Stable/A-1	2
Orange and Rockland Utilities Inc.	A/Stable/A-1	2
Rockland Electric Co.	A/Stable/--	2
Consolidated Edison Inc.	A/Stable/A-1	2
Laclede Gas Co.	A/Stable/A-1	3
Laclede Group Inc.	A/Stable/--	3
Atlantic City Sewerage Co.	A/Stable/--	3
Niagara Mohawk Power Corp.	A/Stable/--	3
Central Hudson Gas & Electric Co.	A/Stable/--	3
American Water Capital Corp.	A/Negative/	2
Boston Gas Co.	A/Negative/--	2
Colonial Gas Co.	A/Negative/--	2
Middlesex Water Co.	A/Negative/--	3
York Water Co. (The)	A-/Stable/--	2
Alabama Gas Corp.	A-/Stable/--	2
Atlanta Gas Light Co.	A-/Stable/--	2
Public Service Co. of North Carolina Inc.	A-/Stable/A-2	2
Wisconsin Gas Co.	A-/Stable/A-2	2
North Shore Gas Co.	A-/Stable/A-2	2
Peoples Gas Light & Coke Co.	A-/Stable/A-2	2
ONEOK Inc.	A-/Stable/A-2	6
Indiana Gas Co. Inc.	A-/Negative/--	1
Southern California Water Co.	A-/Negative/--	3
American States Water Co.	A-/Negative/--	3
United Water New Jersey	A-/Negative/--	4

United Waterworks	A-/Negative/--	4
PPL Electric Utilities Corp.	A-/Negative/--	4
Commonwealth Edison Co.	A-/Negative/A-2	4
PECO Energy Co.	A-/Negative/A-2	4
Central Illinois Public Service Co.	A-/CW-Neg/--	3
Western Massachusetts Electric Co.	BBB+/Stable/--	1
Cascade Natural Gas Corp.	BBB+/Stable/--	2
South Jersey Gas Co.	BBB+/Stable/--	2
Baltimore Gas & Electric Co.	BBB+/Stable/A-2	3
Connecticut Natural Gas Corp.	BBB+/Negative/--	3
Southern Connecticut Gas Co.	BBB+/Negative/--	3
Central Maine Power Co.	BBB+/Negative/--	3
Atlantic City Electric Co.	BBB+/Negative/A-2	3
Potomac Electric Power Co.	BBB+/Negative/A-2	3
Delmarva Power & Light Co.	BBB+/Negative/A-2	3
Yankee Gas Services Co.	BBB+/Negative/--	3
Connecticut Light & Power Co.	BBB+/Negative/--	3
UGI Utilities Inc.	BBB+/Negative/--	4
Bay State Gas Co.	BBB/Stable/--	2
AEP Texas Central Co.	BBB/Stable/--	2
AEP Texas North Co.	BBB/Stable/--	2
Southwest Gas Corp.	BBB-/Stable/--	3
Columbus Southern Power Co.	BBB/Stable/--	3
Ohio Power Co.	BBB/Stable/--	3
Public Service Electric & Gas Co.	BBB/Stable/A-2	3
Oncor Electric Delivery Co.	BBB/Negative/--	2
Southern Union Co.	BBB/Negative/--	3
Centerpoint Energy Houston Electric LLC	BBB/Negative/--	3
CenterPoint Energy Resources Corp.	BBB/Negative/--	3
Duquesne Light Co.	BBB/Negative/	4
Duquesne Light Holdings Inc.	BBB/Negative/ --	5
TXU Gas Co.	BBB/CW-Dev/--	3
Jersey Central Power & Light Co.	BBB-/Stable/--	4
Metropolitan Edison Co.	BBB-/Stable/--	4
Pennsylvania Electric Co.	BBB-/Stable/--	4
Texas-New Mexico Power Co.	BB+/Stable/--	4
AmeriGas Partners L.P.	BB+/Stable/--	7
NUI Utilities Inc.	BB/CW-Dev/--	4

Suburban Propane Partners L.P.	BB-/Stable/--	8
Star Gas Partners L.P.	BB-/Stable/--	8
SEMCO Energy Inc.	BB-/Negative/--	5
Ferrellgas Partners L.P.	BB-/Negative/--	8
Potomac Edison Co.	B/Stable/--	3
West Penn Power Co.	B/Stable/--	3
Illinova Corp.	B/Negative/--	7
NorthWestern Corp.	D/NM/--	7
2. Transmission Only - Electric, Gas, and Other		
Questar Pipeline Co.	A+/Negative/--	3
Mid-West Independent Transmission System Operator Inc.	A/Stable/--	1
American Transmission Co.	A/Stable/A-1	1
New England Power Co.	A/Stable/A-1	1
Colonial Pipeline Co.	A/Stable/A-1	3
Dixie Pipeline Co.	--/--/A-1	3
Plantation Pipeline Co.	--/--/A-1	3
Explorer Pipeline Co.	A/Stable/A-1	4
Northern Natural Gas Co.	A-/Positive/--	2
Buckeye Partners L.P.	A-/Stable/--	4
Kern River Gas Transmission Co.	A-/Negative/--	3
Northern Border Pipeline Co.	A-/CW-Neg/--	2
Texas Gas Transmission LLC	BBB+/Stable/--	3
Iroquois Gas Transmission System L.P.	BBB+/Stable/--	3
Florida Gas Transmission Co.	BBB/Stable/--	2
International Transmission Co.	BBB/Stable	2
ITC Holding Corp.	BBB/Stable	2
Texas Eastern Transmission L.P.	BBB/Stable/--	3
PanEnergy Corp.	BBB/Stable/--	3
TE Products Pipeline Co. L.P.	BBB/Stable/--	4
TEPPCO Partners L.P.	BBB/Stable/--	4
Panhandle Eastern Pipeline LLC	BBB/Negative/--	3
Noark Pipeline Finance LLC	BBB/Negative/--	4
Southern Star Central Gas Pipeline Inc.	BB/Stable/--	3
Transwestern Pipeline Co.	BB/CW-Dev/--	4
Transcontinental Gas Pipe Line Corp.	B+/Negative/--	2
Northwest Pipeline Corp.	B+/Negative/--	2
Colorado Interstate Gas Co.	B-/Negative/--	2
Southern Natural Gas Co.	B-/Negative/--	2

ANR Pipeline Co.	B-/Negative/--	3
Tennessee Gas Pipeline Co.	B-/Negative/--	3
El Paso Tennessee Pipeline Co.	B-/Negative/--	3
El Paso Natural Gas Co.	B-/Negative/--	4
Gas Transmission-Northwest Corp.	CC/CW-Pos/--	2
3. Integrated Electric, Gas, and Combination Utilities		
Wisconsin Public Service Corp.	AA-/Stable/A-1+	4
Madison Gas & Electric Co.	AA/Negative/A-1+	4
Southern Co.	A/Stable/A-1	4
Georgia Power Co.	A/Stable/A-1	4
Alabama Power Co.	A/Stable/A-1	4
Mississippi Power Co.	A/Stable/A-1	4
Gulf Power Co.	A/Stable/--	4
Savannah Electric & Power Co.	A/Stable/--	4
San Diego Gas & Electric Co.	A/Stable/A-1	5
MidAmerican Energy Co.	A/Stable/A-1	5
Questar Corp.	--/--/A-1	6
Equitable Resources Inc.	A/Stable/A-1	6
Florida Power & Light Co.	A/Negative/A-1	4
South Carolina Electric & Gas Co.	A-/Stable/A-2	4
SCANA Corp.	A-/Stable/--	4
Wisconsin Electric Power Co.	A-/Stable/A-2	4
AGL Resources Inc.	A-/Stable/A-2	4
Virginia Electric & Power Co. (Dominion Virginia)	A-/Stable/A-2	5
Idaho Power Co.	A-/Stable/A-2	5
IDACORP Inc.	A-/Stable/A-2	5
Energen Corp.	A-/Stable/--	6
Vectren Utility Holdings Inc.	A-/Negative/A-2	3
Wisconsin Power & Light Co.	A-/Negative/A-2	4
Atmos Energy Corp.	A-/Negative/A-2	4
Southern Indiana Gas & Electric Co.	A-/Negative/--	5
Montana-Dakota Utilities Co.	A-/Negative/--	5
PacifiCorp	A-/Negative/A-2	5
Northern Border Partners L.P.	A-/CW-Neg/--	4
Central Illinois Light Co.	A-/CW-Neg/--	5
CILCORP	A-/CW-Neg/--	5
Union Electric Co.	A-/CW-Neg/A-2	5
Ameren Corp.	A-/CW-Neg/A-2	5

New Business Profile Scores Assigned for U.S. Utility and Power Companies; Financial Guidelines Revised

Cincinnati Gas & Electric Co.	BBB+/Stable/A2-		4
Oklahoma Gas & Electric Co.	BBB+/Stable/A-2		4
Northern States Power Wisconsin	BBB+/Stable /A-2		5
Kentucky Utilities Co.	BBB+/Stable/A-2		5
Louisville Gas & Electric Co.	BBB+/Stable/A-2		5
Allete Inc.	BBB+/Stable/A-2		5
Wisconsin Energy Corp.	BBB+/Stable/A-2		5
PSI Energy Inc.	BBB+/Stable/A-2		5
Union Light Heat & Power Co.	BBB+/Stable/--		5
Hawaiian Electric Co. Inc.	BBB+/Stable/A-2		6
Enogex Inc.	BBB+/Stable/--		6
National Fuel Gas Co.	BBB+/Stable/A-2		7
Energy East Corp.	BBB+/Negative/--A2		3
RGS Energy Group Inc.	BBB+/Negative/--		4
Rochester Gas & Electric Corp.	BBB+/Negative/--		4
Michigan Consolidated Gas Co.	BBB+/Negative/A-2		4
Interstate Power & Light Co.	BBB+/Negative/A-2		5
Public Service Co. of New Hampshire	BBB+/Negative/--		5
Kaneb Pipe Line Operating Partnership L.P.	BBB+/Negative/--		5
Consolidated Natural Gas Co.	BBB+/Negative/A-2		6
Detroit Edison Co.	BBB+/Negative/A-2		6
Questar Market Resources Inc.	BBB+/Negative/--		8
Portland General Electric Co.	BBB+/CW-Neg./A-2		5
Columbia Energy Group	BBB/Stable/--		3
NiSource Inc.	BBB/Stable/--		4
Xcel Energy Inc.	BBB/Stable/A-2		5
Public Service Co. of Colorado	BBB/Stable /A-2		5
Northern States Power Co.	BBB/Stable /A-2		5
Southwestern Public Service Co.	BBB/Stable /A-2		5
Appalachian Power Co.	BBB/Stable/--		5
Kentucky Power Co.	BBB/Stable/--		5
Public Service Co. of Oklahoma	BBB/Stable/--		5
Southwestern Electric Power Co.	BBB/Stable/--		5
Northern Indiana Public Service Co.	BBB/Stable/--		5
Entergy Arkansas Inc.	BBB/Stable/--		5
Entergy Louisiana Inc.	BBB/Stable/--		5
Progress Energy Florida	BBB/Stable/--		5
Progress Energy Carolinas Inc.	BBB/Stable/A-2		5

Kansas City Power & Light Co.	BBB/Stable/A-2	6
PNM Resources Inc.	BBB/Stable/--	6
Southern California Edison Co.	BBB/Stable/A-2	6
Empire District Electric Co.	BBB/Stable/A-2	6
Entergy Mississippi Inc.	BBB/Stable/--	6
Entergy New Orleans Inc.	BBB/Stable/--	6
Duke Energy Field Services LLC	BBB/Stable/A-2	6
Arizona Public Service Co.	BBB/Negative/A-2	5
TXU U.S. Holdings Co.	BBB/Negative/--	5
Pinnacle West Capital Corp.	BBB/Negative/A-2	6
Cleco Power LLC	BBB/Negative/A-3	6
Puget Sound Energy Inc.	BBB-/Positive/A-3	5
Puget Energy Inc.	BBB-/Positive/--	5
Green Mountain Power Corp.	BBB-/Stable/--	5
Public Service Co. of New Mexico	BBB-/Stable/A-2	6
Pacific Gas & Electric Co.	BBB-/Stable/ --	6
Cleveland Electric Illuminating Co.	BBB-/Stable/--	6
Ohio Edison Co.	BBB-/Stable/--	6
Toledo Edison Co.	BBB-/Stable/--	6
Pennsylvania Power Co.	BBB-/Stable/--	6
El Paso Electric Co.	BBB-/Stable/--	6
Central Vermont Public Service Corp.	BBB-/Stable/--	6
Entergy Gulf States Inc.	BBB-/Stable/--	6
System Energy Resources Inc.	BBB-/Stable/--	7
Tampa Electric Co.	BBB-/Negative/A-3	4
Black Hills Power Inc.	BBB-/Negative/--	6
Westar Energy Inc.	BB+/Positive/--	5
Kansas Gas & Electric Co.	BB+/Positive/--	6
Indianapolis Power & Light Co.	BB+/Stable/--	4
IPALCO Enterprises Inc.	BB+/Stable/--	4
Enterprise Products Operating L.P.	BB+/Stable/--	6
Enterprise Products Partners L.P.	BB+/Stable/--	6
GulfTerra Energy Partners L.P.	BB+/CW-Neg/--	6
Consumers Energy Co.	BB/Negative/--	6
Tucson Electric Power Co.	BB/CW-Neg/--	6
Dayton Power & Light Co.	BB-/CW-Neg/ -	7
Monongahela Power Co.	B/Stable/--	5
Nevada Power Co.	B+/Negative/--	7
Sierra Pacific Power Co.	B+/Negative/--	7

Sierra Pacific Resources	B+/Negative/--	7
4. Diversified Energy and Diversified Non-Energy		
WPS Resources Corp.	A/Stable/A-1	5
KeySpan Corp.	A/Negative/A-1	4
FPL Group Inc.	A/Negative/--	6
Peoples Energy Corp.	A-/Stable/A-2	5
Vectren Corp.	A-/Negative/--	4
PacifiCorp Holdings Inc.	A-/Negative/--	5
Exelon Corp.	A-/Negative/A-2	7
MDU Resources Group Inc.	A-/Negative/A-2	7
Centennial Energy Holdings Inc.	A-/Negative/A-2	8
Otter Tail Corp.	A-/Negative/--	8
Kinder Morgan Energy Partners L.P.	BBB+/Stable/A-2	4
Northeast Utilities	BBB+/Stable/--	5
OGE Energy Corp.	BBB+/Stable/A-2	6
LG&E Energy Corp.	BBB+/Stable/--	6
Cinergy Corp.	BBB+/Stable/A-2	6
Constellation Energy Group Inc.	BBB+/Stable/A-2	7
Sempra Energy	BBB+/Stable/A-2	7
Pepco Holdings Inc.	BBB+/Negative/A-2	5
Conectiv	BBB+/Negative/--	5
Alliant Energy Corp.	BBB+/Negative/A-2	6
DTE Energy Co.	BBB+/Negative/A-2	6
Dominion Resources Inc.	BBB+/Negative/A-2	7
Kinder Morgan Inc.	BBB/Stable/A-2	5
American Electric Power Co. Inc.	BBB/Stable/A-2	6
Entergy Corp.	BBB/Stable/--	6
Hawaiian Electric Industries Inc.	BBB/Stable/A-2	6
Progress Energy Inc.	BBB/Stable/A-2	6
PPL Corp.	BBB/Stable/--	7
Public Service Enterprise Group Inc.	BBB/Stable/A-2	7
Great Plains Energy Inc.	BBB/Stable/--	7
Duke Energy Corp.	BBB/Stable/A-2	7
Duke Capital Corp.	BBB/Stable/A-2	8
TXU Corp.	BBB/Negative/--	5
Centerpoint Energy Inc.	BBB/Negative/--	5
Cleco Corp.	BBB/Negative/A-3	6
Potomac Capital Investment Corp.	BBB/Negative/--	8
MidAmerican Energy Holdings Co.	BBB-/Positive/--	5

FirstEnergy Corp.	BBB-/Stable/--	6
TECO Energy Inc.	BBB-/Negative/A-3	5
Black Hills Corp.	BBB-/Negative/--	8
Avista Corp.	BB+/Stable/--	6
Edison International	BB+/Stable/--	6
TNP Enterprises	BB+/Stable/--	6
New York Water Service Corp.	BB/Stable	7
CMS Energy Corp.	BB/Negative/--	7
DPL Inc.	BB- /CW-Neg/--	8
Williams Companies Inc. (The)	B+/Negative/--	8
Allegheny Energy Inc.	B/Stable/--	7
Dynegy Inc.	B/Negative/--	8
Dynegy Holdings Inc.	B/Negative/--	9
El Paso CGP Corp.	B-/Negative/--	6
Aquila Inc.	B-/Negative/--	8
El Paso Corp.	B-/Negative/--	8
5. Energy Merchants/Power Developers/Trading and Marketing		
Entergy-Koch L.P.	A/Stable/--	9
KeySpan Generation LLC	A/Negative/--	5
FPL Group Capital	A/Negative/A-1	8
Exelon Generation Co.	A-/Negative/A-2	8
AmerenEnergy Generating Co.	A-/CW-Neg/--	8
Southern Power Co.	BBB+/Stable/--	6
LG&E Capital Corp.	BBB+/Stable/A-2	9
Alliant Energy Resources Inc.	BBB+/Negative/--	9
American Ref-Fuel Co. LLC	BBB/Stable/--	6
PSEG Power LLC	BBB/Stable/--	8
PPL Energy Supply LLC	BBB/Stable/--	8
TXU Energy Co. LLC	BBB/Negative/--	7
Duke Energy Trading and Marketing LLC	BBB-/Negative/--	10
Northeast Generation Company	BB+/Negative/--	9
Cogentrix Energy	BB-/Stable/--	6
PSEG Energy Holdings Inc.	BB-/Stable/--	9
AES Corp.	B+/Stable/--	9
NRG Energy Inc.	B+/Stable	9
Allegheny Energy Supply Co. LLC	B/Stable/--	8
Reliant Resources Inc.	B/Negative/--	8
Calpine Corp	B/Negative/--	9
Edison Mission Energy	B/Negative/--	9

Orion Power Holdings Inc	B/Negative/--		9
Reliant Energy Mid-Atlantic Power Holdings LLC	B/Negative/--		9
Mirant Americas Generation Inc.	D/--/--		10
Mirant Americas Energy Marketing L.P.	D/--/--		10
Mirant Corp.	D/--/--		10
NEGT Energy Trading Holdings Corp	D/--/--		10
PG&E National Energy Group	D/--/--		10
USGen New England Inc.	D/--/--		10

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Research:

Research Update: Hawaiian Electric Industries And Utility Units Ratings Affirmed; Outlook Revised To Negative

Publication date: 22-Apr-2005
Primary Credit Analyst(s): Barbara A Eiseman, New York (1) 212-438-7666; barbara_eiseman@standardandpoors.com

Credit Rating: BBB/Negative/A-2

Rationale

On April 22, 2005, Standard & Poor's Ratings Services affirmed its 'BBB' corporate credit rating on Hawaiian Electric Industries Inc. (HEI) and its 'BBB+' corporate credit ratings on subsidiary Hawaiian Electric Co. Inc. and its units, Hawaii Electric Light Co. Inc. and Maui Electric Co. Ltd. At the same time, Standard & Poor's revised its outlook on the companies to negative from stable.

The outlook revision reflects a declining trend in HEI's consolidated financial condition, despite the strong Hawaii economy and the company's efforts in recent years to strengthen capital structure balance. The company's financial metrics have been pressured owing to rising operating expenses, yet to be recovered investments, and the long-term lack of rate relief. Absent a supportive rate decision in Hawaiian Electric's pending rate case, prospective key financial metrics may not support a financial profile that is commensurate for the current ratings.

The ratings on HEI are based on the consolidated credit profile of HEI's family of companies, which include the regulated electric utility Hawaiian Electric and its two utility subsidiaries (81% of core revenues and 64% of operating income as of Dec. 31, 2004) and the riskier financial services operations of subsidiary American Savings Bank FSB, which contributed 19% of core revenues and 39% of operating income as of Dec. 31, 2004.

HEI has a satisfactory business profile and weak financial measures. The company's business position is characterized by limited competitive threats due to the utility's geographic isolation, nominal stranded-asset risk, modest rate-relief needs, an excellent fuel clause, and steady banking operations. American Savings Bank's consistent earnings are driven by net interest income from its low-cost deposit funding and low-risk earning-asset base. These strengths are tempered by Hawaii's tourism-driven economy, dependence on fuel oil, significant purchased-power obligations, and support of the somewhat riskier banking businesses.

Hawaii's economy has been growing modestly during the past several years and is expected to grow by 3.1% after inflation in 2005. The visitor industry is Hawaii's largest economic driver and has recovered from the adverse effects of the 2001 terrorist attacks. Total visitor arrivals were up 8.3% in 2004. Domestic arrivals were well above record levels set in 2000 and international arrivals are starting to increase as the Japanese economy has returned to growth. Strength in key nontourism sectors, particularly real estate and the growing military commitment, coupled with low interest rates, have resulted in solid construction and real estate sales activity although future growth in real estate may slow with rising interest rates. Hawaii's future economic growth is expected to be tied primarily to the rate of expansion in the mainland U.S. and Japan economies and increased military spending, yet remains vulnerable to uncertainties in the world's geopolitical environment.

Internal cash covered about 70% of HEI's capital program in 2004. Assuming no new capacity additions, (which may eventually be necessary to meet load growth on Oahu), internally generated funds should satisfy the bulk of construction expenditures for the next five years. Prospective construction outlays will focus predominantly on additions and improvements to transmission facilities, and to a lesser extent, on generation projects as well as energy solutions and customer-choice technologies.

HEI's bondholder protection parameters are subpar for the current ratings. Although total debt to capital (adjusted for off-balance-sheet obligations, such as purchased-power contracts, quarterly income preferred securities, and Hawaiian Electric's $50 million trust-originated preferred securities) had declined to 56% at Dec. 31, 2004 from 58% at the end of 2003, it is still liberal for a mid 'BBB' rating. Adjusted funds from operations (FFO) interest coverage is a mediocre 3.1x, which is at the lower end of the 'BBB' category benchmark. Adjusted FFO to total debt is just 16.1%, which is commensurate with noninvestment grade guideposts. However, with rate relief, tight cost controls, the impact on the company's earnings from continued expansion of Hawaii's economy, and HEI's other credit supportive actions, the company's overall financial condition should improve.

Importantly, a responsive rate order from the Hawaii Public Utilities Commission with regard to Hawaiian Electric's pending rate case for a $98.6 million (9.9%) rate hike is crucial to help lift the company's key financial measures to more appropriate levels for the ratings. Although there are no time restrictions for the commission to issue a final order, an interim decision is possible by the fourth quarter of 2005. Rate relief is needed to recover the costs of reliability investments made since 1995, which have included a number of transmission upgrades, the costs associated with a purchased-power contract, a new fuel oil pipeline, and costs to ensure the continuation and expansion of energy efficiency and conservation programs.

Short-term credit factors

The short-term corporate credit and commercial paper ratings on HEI and Hawaiian Electric are 'A-2', incorporating solid liquidity and the ability to internally fund the bulk of dividends and capital expenditures in nearby years. HEI faces a manageable maturity schedule, with $37 million due in December 2005. Hawaiian Electric has no maturing long-term debt until 2012. As of Dec. 31, 2004, HEI had $12 million of cash and cash equivalents (excluding American Savings Bank's cash and cash equivalents). HEI and Hawaiian Electric had bank lines totaling $80 million and $110 million, respectively, at the end of 2004 .

Covenants in HEI's and Hawaiian Electric's lines require Hawaiian Electric to maintain a consolidated equity capitalization ratio (exclusive of short-term debt) of at least 35%. As of Dec. 31, 2004, Hawaiian Electric's consolidated common equity to capitalization ratio was 56%. Certain HEI lines of credit totaling $20 million and $45 million require the company to maintain a consolidated net worth, exclusive of intangible assets, of at least $900 million and $850 million, respectively, which at the end of December 2004 was $1.1 billion. The line of credit agreements do not contain interest coverage ratio requirements. None of HEI's or Hawaiian Electric's lines contains material adverse change clauses or rating triggers that affect access to the lines of credit.

HEI's capital outlays are expected to decline to about $193 million in 2005 from around $215 million in 2004. Roughly 75% of the 2005 construction program is expected to be internally funded. Importantly, ongoing growth in the Hawaii economy should allow the electric utility to generate relatively stable cash flows and the bank to maintain normal cash dividend levels (50% of its earnings) while still supporting its own business growth.

HEI has $150 million of debt capacity remaining under a Rule 415 shelf registration. As of Dec. 31, 2004, proceeds of approximately

$12 million from a previous sale of special purpose revenue bonds issued by the State of Hawaii's Department of Budget and Finance for the benefit of Hawaiian Electric remained undrawn.

Outlook

The negative outlook reflects HEI's declining financial trend. Failure to strengthen key financial parameters, especially cash flow coverage of debt, a slump in the Hawaii economy, a punitive rate order, and/or an erosion in American Savings Bank's creditworthiness could lead to lower ratings. Conversely, credit supportive actions by the company as well as responsive rate treatment that would enable the company to produce FFO to total debt in the lower to mid-20s percentage range would lead to ratings stability.

Ratings List

	To	From
Hawaiian Electric Industries Inc.		
Corporate credit rating	BBB/Negative/A-2	BBB/Stable/A-2
Senior unsecured debt	BBB	
Preferred Stock	BB+	
Commercial paper	A-2	
Hawaiian Electric Co. Inc.		
Corporate credit rating	BBB+/Negative/A-2	BBB+/Stable/A-2
Senior unsecured debt	BBB+	
Preferred stock	BBB-	
Commercial paper	A-2	
Maui Electric Co. Ltd.		
Corporate credit rating	BBB+/Negative/--	BBB+/Stable/--
Senior unsecured debt	BBB+	
Hawaii Electric Light Co. Inc.		
Corporate credit rating	BBB+/Negative/--	BBB+/Stable/--
Senior unsecured debt	BBB+	

Complete ratings information is available to subscribers of RatingsDirect, Standard & Poor's Web-based credit analysis system, at www.ratingsdirect.com. All ratings affected by this rating action can be found on Standard & Poor's public Web site at www.standardandpoors.com; under Credit Ratings in the left navigation bar, select Find a Rating, then Credit Ratings Search.